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Arizona Corporation Commission

DOCKETED

FEB 29 2008

DOCKETED BY

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF  
TUCSON ELECTRIC POWER COMPANY FOR  
THE ESTABLISHMENT OF JUST AND  
REASONABLE RATES AND CHARGES  
DESIGNED TO REALIZE A REASONABLE  
RATE OF RETURN ON THE FAIR VALUE OF  
ITS OPERATIONS THROUGHOUT THE STATE  
OF ARIZONA.

Docket No. E-01933A-07-0402

THE MATTER OF THE FILING BY TUCSON  
ELECTRIC POWER COMPANY TO AMEND  
DECISION NO. 62103.

Docket No. E-01933A-05-0650

NOTICE OF FILING OF DIRECT TESTIMONY (REVENUE REQUIREMENT)  
AND ATTACHMENTS OF KEVIN C. HIGGINS  
ON BEHALF OF PHELPS DODGE MINING COMPANY AND ARIZONANS FOR  
ELECTRIC CHOICE AND COMPETITION

Phelps Dodge Mining Company and Arizonans for Electric Choice and  
Competition (collectively "AECC"), hereby submits the Direct Testimony (Revenue  
Requirement) and Attachments of Kevin C. Higgins on behalf of AECC in the above

1 captioned Docket.

2 RESPECTFULLY SUBMITTED this 29th day of February 2008.

3 FENNEMORE CRAIG, P.C.

4  
5 By: 

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7 Patrick J. Black

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14 **ORIGINAL +15 COPIES FILED** this  
15 29<sup>th</sup> day of February 2008 with:

16 Docket Control  
17 Arizona Corporation Commission  
18 1200 West Washington  
19 Phoenix, AZ 85007

20  
21 **COPIES of the foregoing HAND DELIVERED**  
22 **AND E-MAILED** this 29<sup>th</sup> day of February 2008 to:

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By: Mary Bollinger

1 **BEFORE THE ARIZONA CORPORATION COMMISSION**

2  
3 IN THE MATTER OF THE APPLICATION )  
4 OF TUCSON ELECTRIC POWER )  
5 COMPANY FOR THE ESTABLISHMENT )  
6 OF JUST AND REASONABLE RATES )  
7 AND CHARGES DESIGNED TO REALIZE ) Docket No. E-01933A-07-0402  
8 A REASONABLE RATE OF RETURN ON )  
9 THE FAIR VALUE OF ITS OPERATIONS )  
10 THROUGHOUT THE STATE OF )  
11 ARIZONA )  
12 \_\_\_\_\_ )

13 IN THE MATTER OF THE FILING BY )  
14 TUCSON ELECTRIC POWER COMPANY ) Docket No. E-01933A-05-0650  
15 TO AMEND DECISION NO. 62103 )  
16

17  
18 **Direct Testimony of Kevin C. Higgins**

19 **on behalf of**

20 **Phelps Dodge Mining Company and**

21 **Arizonans for Electric Choice and Competition**  
22  
23

24 **Revenue Requirement**  
25  
26

27 **February 29, 2008**

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1                                   **DIRECT TESTIMONY OF KEVIN C. HIGGINS**

2

3   **I.     Introduction**

4   **Q.     Please state your name and business address.**

5   A.           Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah,  
6               84111.

7   **Q.     By whom are you employed and in what capacity?**

8   A.           I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies  
9               is a private consulting firm specializing in economic and policy analysis  
10              applicable to energy production, transportation, and consumption.

11   **Q.     On whose behalf are you testifying in this proceeding?**

12   A.           My testimony is being sponsored by Phelps Dodge Mining Company  
13               ("Phelps Dodge") and Arizonans for Electric Choice and Competition ("AECC").  
14               AECC is a business coalition that advocates on behalf of retail electric customers  
15               in Arizona. AECC is a party to the Tucson Electric Power Company ("TEP")  
16               Settlement Agreement that was approved by the Commission, with some  
17               modification, in 1999, and which is the subject of considerable discussion in  
18               TEP's filing in this docket.

19   **Q.     Were you personally involved in the negotiations that resulted in the TEP**  
20   **Settlement Agreement?**

21   A.           Yes, I was closely involved in the negotiations on behalf of AECC. I also  
22               testified before the Commission in support of the Settlement Agreement in 1999.

1   **Q.     Did you testify in the proceeding that addressed TEP's request to amend**  
2       **Decision No. 62103, Docket No. E-01933A-05-0650?**

3   A.           Yes. I filed direct and surrebuttal testimony and was cross examined in  
4       that proceeding. Docket No.E-01933A-05-0650 provided an extensive record  
5       refuting TEP's claim that the 1999 Settlement Agreement requires Standard Offer  
6       generation rates to be set equal to the Market Generation Credit ("MGC"). By this  
7       reference, I am incorporating without change my testimony from Docket No.E-  
8       01933A-05-0650 into my testimony in this proceeding.

9   **Q.     Please describe your professional experience and qualifications.**

10  A.           My academic background is in economics, and I have completed all  
11       coursework and field examinations toward the Ph.D. in Economics at the  
12       University of Utah. In addition, I have served on the adjunct faculties of both the  
13       University of Utah and Westminster College, where I taught undergraduate and  
14       graduate courses in economics. I joined Energy Strategies in 1995, where I assist  
15       private and public sector clients in the areas of energy-related economic and  
16       policy analysis, including evaluation of electric and gas utility rate matters.

17               Prior to joining Energy Strategies, I held policy positions in state and local  
18       government. From 1983 to 1990, I was economist, then assistant director, for the  
19       Utah Energy Office, where I helped develop and implement state energy policy.  
20       From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County  
21       Commission, where I was responsible for development and implementation of a  
22       broad spectrum of public policy at the local government level.

23  **Q.     Have you previously testified in other cases before this Commission?**

1 A. Yes. I have testified in a number of proceedings before this Commission,  
2 including the generic proceeding on retail electric competition (1998), the  
3 hearings on the Arizona Public Service Company ("APS") Direct Access  
4 Settlement Agreement (1999), the hearings on the TEP Direct Access Settlement  
5 Agreement (1999), the AEPCO transition charge hearings (1999), the  
6 Commission's Track A proceeding (2002), the APS adjustment mechanism  
7 proceeding (2003), the Arizona ISA proceeding (2003), the APS general rate case  
8 (2004), the Trico rate case (2005), the TEP rate review (2005), the APS  
9 emergency interim rate proceeding (2006), the APS general rate case (2006), and  
10 TEP's request to amend Decision No. 62103 (2007).

11 **Q. Have you testified before utility regulatory commissions in other states?**

12 A. Yes. I have testified in over seventy other proceedings on the subjects of  
13 electric utility rates and regulatory policy before state utility regulators in Alaska,  
14 Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky,  
15 Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York,  
16 Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Utah, Virginia,  
17 Washington, West Virginia, and Wyoming. I have also participated in various  
18 Pricing Processes conducted by the Salt River Project Board.

19 A more detailed description of my qualifications is contained in  
20 Attachment A, attached to this testimony.

1    **II.    Overview and Conclusions**

2    **Q.    What is the purpose of your testimony in this phase of the proceeding?**

3    A.            My testimony addresses several revenue requirement issues in TEP's  
4            general rate case filing, and recommends adjustments to TEP's proposed revenue  
5            requirement in support of a just and reasonable outcome.

6            TEP's filing contains proposed rates for three different scenarios: (1)  
7            market-based rates for generation service ("Market Methodology"); (2) cost-of-  
8            service-based rates for generation service ("Cost-of-Service Methodology"); and  
9            (3) a hybrid of cost-of-service and market-based rates ("Hybrid Methodology").

10           With respect to TEP's proposed Market Methodology, I provide a  
11           summary of AECC's position in Docket No. E-01933A-05-0650, which responds  
12           to TEP's claim that the 1999 Settlement Agreement entitles the Company to  
13           charge Standard Offer generation rates based on the MGC methodology effective  
14           January 1, 2009. My testimony in that docket provided an extensive response to  
15           the Company's claim. As I testified in that proceeding, TEP mischaracterizes the  
16           MGC provision in the 1999 Settlement Agreement, and the Company's claim that  
17           Standard Offer generation rates are to be set equal to the MGC is wholly  
18           incorrect. Consequently, TEP's proposed Market Methodology is without  
19           foundation and should be rejected by the Commission.

20           The Hybrid Methodology is offered by TEP as a middle ground between  
21           its Cost-of-Service Methodology and Market Methodology. However, as with the  
22           Market Methodology, the Hybrid Methodology proposal originates from the

1 premise that TEP is entitled to set rates based on the MGC. As this premise is  
2 without foundation, I recommend against adoption of the Hybrid Methodology.

3 Because TEP's claim that it is entitled to charge Standard Offer generation  
4 rates based on the MGC was fully addressed in Docket No. E-01933A-05-0650,  
5 and because I have incorporated into this testimony by reference my previous  
6 response to that claim, I will not repeat here my full refutation of the Company's  
7 argument on this point. Instead, the primary focus of my testimony in this phase  
8 of the proceeding is to address TEP's requested revenue requirements associated  
9 with the Company's Cost-of-Service Methodology.

10 **Q. Please summarize your conclusions and recommendations with respect to**  
11 **revenue requirement issues in this proceeding.**

12 **A.** I offer the following conclusions and recommendations:

13 (1) The appropriate approach for setting rates after January 1, 2009 is on a cost-  
14 of-service basis. The TEP proposal that best reflects cost-of-service is its  
15 Cost-of-Service Methodology. I recommend the following adjustments to the  
16 revenue requirement requested by TEP in its Cost-of-Service Methodology  
17 proposal:  
18

19 (a) TEP's proposed Termination Cost Regulatory Asset Charge  
20 ("TCRAC") is without merit and should be rejected. Elimination of  
21 this proposed charge reduces TEP's requested revenue requirement by  
22 \$117.6 million.  
23

24 (b) TEP's proposed fixed cost recovery rate for Springerville Unit No. 1  
25 of \$25.67 per kW-month significantly overstates the Company's test  
26 year expenses for fixed costs under its capital lease. The fixed cost  
27 recovery rate should be reduced to \$18.63 per kW-month to better  
28 reflect the Company's fixed cost expense in the test year. This  
29 adjustment reduces TEP's requested revenue requirement by \$30.5  
30 million.  
31

32 (c) TEP inappropriately excludes from base rates any credit to customers  
33 attributable to the margins from short-term sales. Instead of such an  
34 exclusion, 100 percent of the test year margins from short-term sales

1 should be reflected in base rates. This adjustment reduces TEP's  
2 requested revenue requirement by \$24.0 million.  
3

4 (d) TEP has proposed the creation of regulatory assets to recover certain  
5 costs associated with the buyouts of coal contracts to supply the Sundt  
6 and San Juan Stations. I agree with recognizing regulatory assets for  
7 the respective buyouts, but recommend that the amortization period  
8 start at the time the buyouts occurred, 2002. At the same time, because  
9 the buyouts will provide cost avoidance over an extended period of  
10 time, the amortization periods should be extended from the four-year  
11 period proposed by TEP to a ten-year period. This adjustment reduces  
12 TEP's proposed revenue requirements by \$5.5 million per year.  
13

14 (e) I recommend against adoption of TEP's proposal to recover the fixed  
15 costs of the Luna Energy Facility through a "market-based capacity  
16 charge" of \$7.00 per kW-month. If customers are going to be  
17 responsible for the recovery of Luna Energy Facility costs, then the  
18 recovery of fixed costs should be based on inclusion of the facility's  
19 net plant in service in rate base, and recovery of fixed O&M costs  
20 based on test year pro-forma expenses. My recommendation reduces  
21 TEP's proposed revenue requirements by \$6.7 million per year.  
22

23 These five adjustments reduce TEP's requested revenue requirement by a total  
24 of \$184.2 million. By themselves, these adjustments demonstrate that TEP's  
25 current rates should be *reduced* by at least \$3.5 million (using TEP's  
26 currently-filed fuel and purchased power cost forecast).  
27

28 (2) I am neither recommending for nor against adoption of a Purchased Power and  
29 Fuel Adjustment Clause ("PPFAC") for TEP. In my opinion, TEP has not  
30 produced compelling quantitative evidence demonstrating its financial  
31 exposure to fuel volatility. At the same time, I am aware of the significant  
32 exposure to fuel volatility faced by the other major jurisdictional utility, APS,  
33 and acknowledge the possibility that TEP may also face material exposure in  
34 this regard. If a PPFAC is adopted, then I recommend the following  
35 modifications to the structure proposed by TEP:  
36

37 (a) The Base Cost of Fuel and Purchased Power should include a credit to  
38 customers for 100 percent of the margins from short-term sales during  
39 the test year.  
40

41 (b) Rather than setting each year's fuel and purchased power recovery  
42 based on a forecast, as TEP proposes, the PPFAC should simply  
43 recover the difference between actual purchased power and fuel costs  
44 and the Base Cost of Fuel and Purchased Power in rates.  
45

46 (c) To maintain incentives for the utility to manage its costs effectively,  
47 responsibility for changes in fuel and purchased power costs should be

1 shared between the utility and customers. I recommend a 90/10  
2 sharing between customers and TEP.

3  
4 (d) The same 90/10 sharing percentage used for fuel and purchased power  
5 should be applied to changes in short-term sales margins (relative to  
6 the margins included in the Base Cost of Fuel and Purchased Power).  
7 That is, 90 percent of any change in short-term sales margins should  
8 accrue to customers.

9  
10 (e) The PPFAC rate charged to customers should be differentiated by  
11 voltage level to properly reflect line loss differences among customers  
12 taking service at different voltage levels.

13  
14 (3) If the Cost-of-Service Methodology is adopted and if a PPFAC is also  
15 adopted, then I recommend that the True-Up Revenues established in Docket  
16 No. 69658 should be applied as a credit against future PPFAC balances. These  
17 revenues should earn interest at the interest rate approved for PPFAC  
18 balances. Alternatively, if the Cost-of-Service Methodology is adopted and if  
19 a PPFAC is not adopted, then I recommend that the True-Up Revenues be  
20 returned to customers over a three-year period, and earn interest at the rate  
21 applied to TEP's regulatory asset balances. These two alternative  
22 recommendations assume that TEP's proposed TCRAC is rejected by the  
23 Commission. If, for some reason, the TCRAC is adopted in whole or in part,  
24 then the True-Up Revenues should be applied against the TCRAC balance.

25  
26 Although the True-Up Revenues properly belong to customers, AECC would  
27 be willing to accept a resolution in which the True-Up Revenues were not  
28 returned to customers under the Cost-of-Service Methodology, if, and only if,  
29 this concession were accompanied by TEP's withdrawal of all claims that the  
30 Company would be harmed by setting rates at cost-of-service. Absent such  
31 action by TEP, the True-Up Revenues should be returned in full to customers.

32  
33 If the Cost-of-Service Methodology is not adopted, then the True-Up  
34 Revenues should be returned to customers over a twelve-month period, and  
35 should earn interest at the same return applied to TEP's regulatory assets.

36  
37 (4) TEP has offered its Cost-of-Service Methodology and Hybrid Methodology  
38 with certain direct access conditions attached, namely, that direct access rights  
39 for customers be eliminated in the former case and restricted to customers 3  
40 MW and greater in the latter case. I recommend that the Commission reject  
41 both of those conditions. Direct access is a statewide issue. Standard offer  
42 generation service in both the APS and SRP service territories is based on  
43 cost-of-service, and customers in those territories have not been forced to  
44 relinquish their rights to direct access. If issues of direct access are to be  
45 addressed, it should occur in its own docket. Customer direct access rights  
46 should not be rolled back piecemeal as part of this proceeding.

1    **III.    Review of AECC's Response to TEP's Assertions Regarding Market Pricing**  
2    **of Retail Service in Docket No. E-01933A-05-0650**

3    **Q.    What does TEP claim with respect to the MGC and retail prices?**

4    A.            TEP claims that the 1999 Settlement Agreement established the rate for  
5            Standard Offer generation service at a price equal to the MGC, and that further,  
6            the Company is entitled to charge Standard Offer generation rates based on the  
7            MGC methodology effective January 1, 2009. In Docket No. E-01933A-05-0650,  
8            I provided extensive testimony demonstrating that neither of these claims is  
9            correct. Staff, RUCO, and the Department of Defense independently concurred  
10           with this conclusion.<sup>1</sup>

11   **Q.    Please summarize AECC's position with respect to these claims as presented**  
12   **in your testimony and AECC's other filings in Docket No. E-01933A-05-0650.**

13   A.            AECC's position may be summarized in the following nine points:  
14            (1) The MGC was developed for the sole purpose of calculating stranded costs.  
15            (2) There is no basis in the 1999 Settlement Agreement for setting Standard Offer  
16            generation rates equal to the MGC, either in the past, present or after January 1,  
17            2009.  
18            (3) The Electric Competition Rules require that Standard Offer rates be based on  
19            cost of service.  
20            (4) The 1999 Settlement Agreement does not provide for market-based rates for  
21            Standard Offer generation service except as such rates would have resulted from  
22            implementing the divestiture requirement in Section 3.1 of the Agreement.  
23            (5) Had TEP's generation assets been divested as initially required in the Electric  
24            Competition Rules and as required in the 1999 Settlement Agreement, then  
25            jurisdiction over these assets would have been transferred to FERC, and output  
26            from these units would have been sold exclusively in wholesale markets, most  
27            likely at FERC-approved market rates. Under such a scenario, cost-based  
28            Standard Offer rates would necessarily reflect the pass-through of market prices  
29             
30             
31             
32           

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<sup>1</sup> See discussion in Decision No. 69568, paragraph 62 [p. 12, lines 7-20].

1 upon expiration of the rate cap on December 31, 2008, subject to approval in a  
2 general rate case. (In this sense, AECC agrees with TEP that there was an  
3 expectation in 1999 that Standard Offer generation rates were to be reflective of  
4 market prices after December 31, 2008.)

5  
6 (6) The Commission's Track A Decision, issued September 10, 2002, directed  
7 TEP to cancel its plans for the divestiture of its assets, nullifying the divestiture  
8 provision in the Settlement Agreement.

9  
10 (7) The Commission's action cancelling the divestiture of TEP's generation assets  
11 eliminated the means through which TEP's Standard Offer generation rates would  
12 have been based on market prices.

13  
14 (8) TEP did not appeal the Track A decision, which I am informed by counsel is  
15 now res judicata, collaterally estopping TEP from arguing that the Decision  
16 improperly altered the Settlement Agreement.

17  
18 (9) In the absence of divestiture, the cost-of-service requirements for Standard  
19 Offer service apply to the costs of TEP's un-divested generation assets.  
20

21 **Q. In point Number 5 above, you stated that AECC agrees with TEP that there**  
22 **was an expectation in 1999 that Standard Offer generation rates were to be**  
23 **reflective of market prices after December 31, 2008. At what point does your**  
24 **position and that of TEP's diverge?**

25 A. It is AECC's position that divestiture of generation assets would have  
26 caused TEP's Standard Offer generation rates to be reflective of market prices  
27 after December 31, 2008. In contrast, TEP maintains that Standard Offer  
28 generation rates after December 31, 2008 are required to be reflective of market  
29 prices because the 1999 Settlement Agreement sets these rates equal to the MGC.  
30 As I stated above, AECC strongly maintains that this claim is untrue, as the  
31 Settlement Agreement contains no such provision.

32 **Q. Given these conclusions, what is your recommendation to the Commission**  
33 **regarding TEP's Market Methodology proposal?**

1 A. The premise behind the Market Methodology proposal is that the 1999  
2 Settlement Agreement provides that the rates for Standard Offer generation  
3 service are to be set equal to the MGC. That claim is incorrect. Further, the means  
4 through which market prices were to be passed through to customers after  
5 December 31, 2008 was eliminated when the Track A Decision nullified the  
6 divestiture requirement in the Settlement Agreement. Consequently, TEP's  
7 proposed Market Methodology is without foundation and should be rejected.

8 **Q. What is your recommendation regarding TEP's Hybrid Methodology**  
9 **proposal?**

10 A. The Hybrid Methodology is offered by TEP as a middle ground between  
11 its Cost-of-Service Methodology and Market Methodology. However, as with the  
12 Market Methodology, the Hybrid Methodology proposal originates from the  
13 premise that TEP is entitled to set rates based on the MGC. As this premise is  
14 without foundation, I recommend against adoption of the Hybrid Methodology. I  
15 address TEP's Hybrid Methodology proposal further in Section VII of this  
16 testimony.

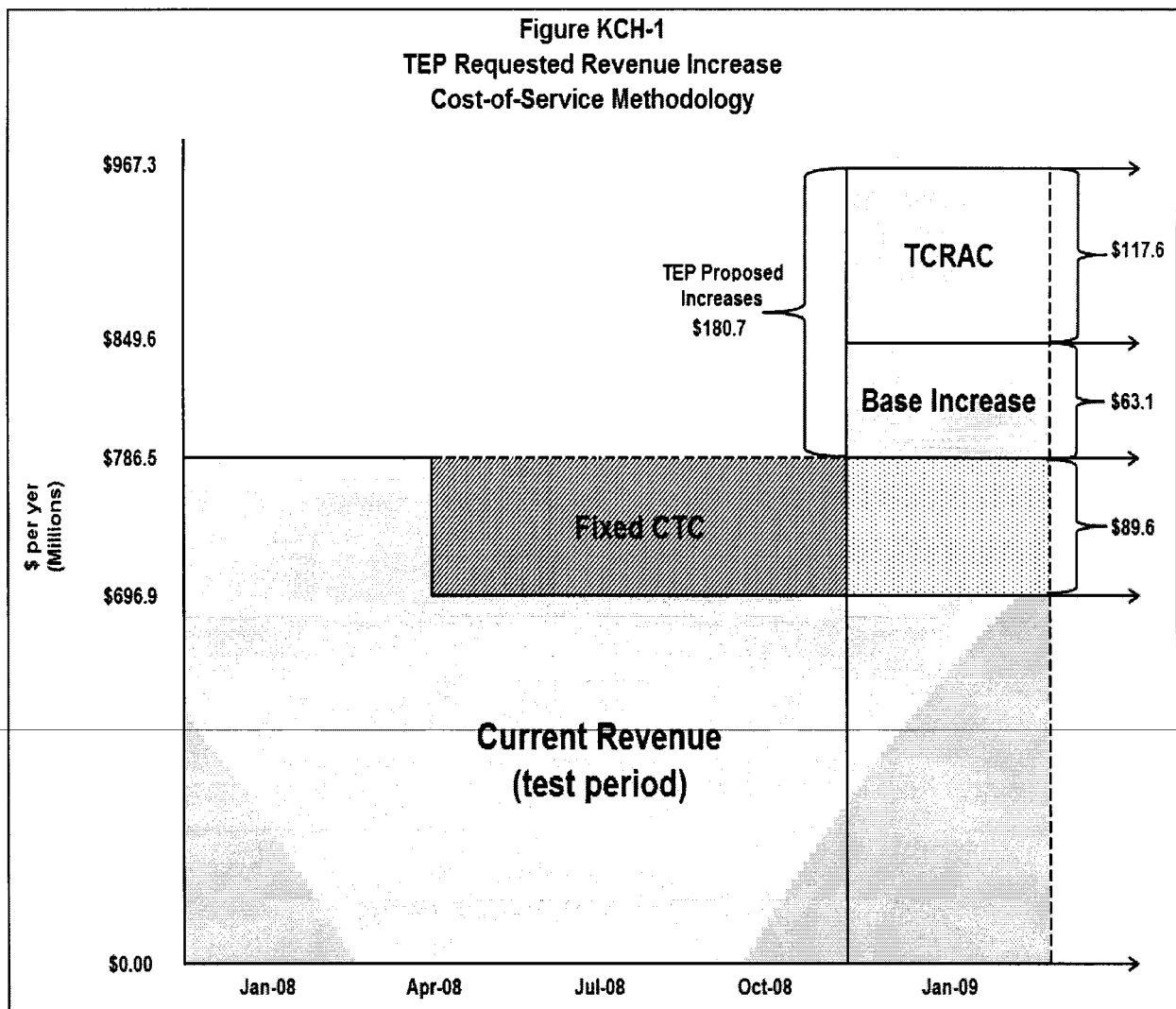
17  
18 **IV. TEP revenue requirements – Cost-of-Service Methodology**

19 **Q. What increase in revenue requirement has TEP requested under its Cost-of-**  
20 **Service Methodology scenario?**

21 A. TEP is requesting an increase in revenue requirement of \$180.7 million  
22 over current rates, or 23 percent, under its Cost-of-Service Methodology scenario.  
23 (In using the term "current rates" I am referring to rates that include the Fixed

CTC component.) This increase is based upon TEP's currently-projected fuel and purchased power price forecast. TEP has stated that it intends to update this forecast (and presumably its requested revenue requirement) during the course of the proceeding.

TEP's requested rate increase is reproduced in Schedule KCH-1, page 1, and is graphically depicted in Figure KCH-1, below.



1 As shown, of the \$180.7 million increase proposed by TEP, \$117.6  
2 million is comprised of the proposed Termination Cost Regulatory Asset Charge  
3 and \$63.1 million represents an increase in base rates.

4 Pursuant to the terms of the 1999 Settlement Agreement, the Fixed CTC is  
5 supposed to be terminated on December 31, 2008, or after it yields stranded cost  
6 recovery of \$450 million, whichever comes first. My understanding is that  
7 recovery of the \$450 million will be achieved around May, 2008. In Decision No.  
8 69568, the Commission determined that in the interest of rate stability, TEP's  
9 Standard Offer rates should remain unchanged pending the outcome of this rate  
10 case; thus, rates will not be reduced by the amount of the Fixed CTC in May 2008  
11 as originally envisaged. However, the Decision also provided that TEP customers  
12 should be protected by providing for a mechanism to refund or credit the  
13 revenues, plus interest, that will continue to be collected by the modified  
14 treatment of the Fixed CTC, until new rates are approved. These revenues are  
15 called True-Up Revenues.

16 On an annualized basis, the Fixed CTC collects approximately \$89.6  
17 million. Therefore, if base rates are viewed as excluding the Fixed CTC  
18 component, then the increase in revenue requirement being requested by TEP  
19 should be viewed as equal to \$270.3 million, i.e., \$180.7 million plus retention of  
20 the \$89.6 million in Fixed CTC revenues.

21 **Q. What adjustments are you recommending with respect to TEP's requested**  
22 **revenue requirements?**

1 A. My recommended adjustments are concentrated on a limited number of  
2 issues. Absence of comment on my part regarding a particular revenue issue does  
3 not signify support (or opposition) toward the Company's filing with respect to  
4 the non-discussed issue. I am recommending the following adjustments to the  
5 revenue requirement proposed by TEP:

6 (1) Removal of TEP's proposed Termination Cost Regulatory Asset Charge  
7 [\$117.6 million];

8 (2) A reduction in TEP's proposed fixed cost recovery rate for Springerville Unit  
9 No. 1 to reflect the Company's fixed cost expense in the test year [\$30.5 million];

10 (3) Inclusion in base rates of 100 percent of off-system sales margins from short-  
11 term sales [\$24.0 million];

12 (4) Recognition of regulatory assets for the buyouts of the coal supply contracts  
13 for the Sundt and San Juan Stations, but initiating the amortization period at the  
14 time the buyouts occurred (2002) and extending the length of the amortization  
15 periods from the four-year period proposed by TEP to a ten-year period [\$5.5  
16 million]; and

17 (5) Elimination of TEP's proposed "market-based capacity charge" of \$7.00 per  
18 kW-month for the Luna Energy Facility, and instead recovering fixed costs

19 through inclusion of the facility's net plant in service in rate base and recovery of  
20 its fixed O&M costs based on test year pro-forma expenses [\$6.7 million].

21 The impact of these five adjustments is shown in Schedule KCH-1, page  
22 2. The cumulative impact of these adjustments reduces TEP's requested revenue  
23 requirement by a total of \$184.2 million (as shown in line 13 of Schedule KCH-1,

1 page 2). These adjustments demonstrate that TEP's current rates should be  
2 *reduced* by at least \$3.5 million (using TEP's currently-filed fuel and purchased  
3 power cost forecast).

4  
5 **A. Termination Cost Regulatory Asset Charge ("TCRAC")**

6 **Q. What is TEP's proposal for a Termination Cost Regulatory Asset Charge**  
7 **("TCRAC")?**

8 A. As explained in the direct testimony of Kentton C. Grant, TEP has  
9 proposed that it be awarded a regulatory asset in the amount of \$788 million if the  
10 Cost-of-Service Methodology is adopted. Mr. Grant asserts that such a regulatory  
11 asset is necessary "in recognition of the economic burden imposed on TEP as a  
12 result of the extended rate freeze and return to full cost-of-service regulation."<sup>2</sup>  
13 The mechanism TEP proposes for recovering this proposed regulatory asset (plus  
14 interest) is the TCRAC, which would be levied for ten years. The first year cost to  
15 TEP customers of the TCRAC would be \$117.6 million.

16 **Q. What is your assessment of this proposal?**

17 A. The TCRAC proposal is without merit and should be rejected. TEP's  
18 claim that it has incurred an economic burden that warrants redress is grounded in  
19 its contention that the 1999 Settlement Agreement set rates equal to the MGC.  
20 According to TEP's argument, setting post-2008 Standard Offer generation rates  
21 based on cost-of-service deprives the Company of this alleged benefit in the  
22 Settlement Agreement. But as I stated above, the MGC issue was thoroughly

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<sup>2</sup> Direct testimony of Kentton C. Grant, p. 2, lines 22-25.

1 addressed in Docket No. E-01933A-05-0650, and the record in that case  
2 demonstrates that TEP's claim that generation rates were to be set equal to the  
3 MGC is simply untrue.

4 That said, I agree that a significant change was made with respect to the  
5 parameters governing the pricing of Standard Offer generation during the 1999-  
6 2008 transition period. That change was the Track A Decision, which nullified the  
7 divestiture requirements of the Electric Competition Rules, the APS Settlement  
8 Agreement, and the TEP Settlement Agreement. In cancelling the divestiture of  
9 TEP's generation assets, the Track A Decision eliminated the means through  
10 which TEP retail customers would be charged market prices for Standard Offer  
11 service. APS clearly recognized these implications and appealed the Track A  
12 Decision, citing among other things, APS's reliance on the divestiture provision  
13 of its Settlement Agreement and the adverse impact to APS and its affiliates from  
14 the cancellation of divestiture.<sup>3</sup> When APS filed its first rate case after the Track  
15 A Decision, it filed to recover Standard Offer generation costs on a cost-of-  
16 service basis.

17 Unlike APS, TEP did not appeal the Track A Decision. If anything, TEP  
18 encouraged the Commission to delay, if not, cancel divestiture of its generation  
19 assets. It is unfathomable to me that TEP did not recognize the implications for its  
20 future Standard Offer generation rates resulting from the cancellation of its asset  
21 divestiture as required by the Track A Decision.

22 **Q. Did TEP have a financial interest in delaying or cancelling divestiture?**

1     A.             Apparently, yes. According to the testimony of TEP witness James S.  
2             Pignatelli in Docket No. E-01933A-05-0650, divestiture would have subjected  
3             TEP to higher federal income taxes as it would have led to a violation of the  
4             provisions of the Company's two-county financing, which conveys special tax  
5             benefits to the Company.<sup>4</sup> As TEP was (and is) operating under a retail rate cap,  
6             the increased income tax expense that would have resulted from divestiture would  
7             have been absorbed by TEP shareholders. Thus, TEP benefitted from the  
8             cancellation of divestiture and the nullification of the divestiture requirement in  
9             the Settlement Agreement. However, while TEP accepted the benefits conveyed  
10            to it by the Track A Decision, the Company is now unwilling to accept the full  
11            consequences of that Decision, namely the implications for Standard Offer  
12            generation rates. Rather than admit that the cause of the change in the basis for  
13            setting Standard Offer generation rates is the Track A Decision, which I am  
14            informed by counsel is res judicata, TEP points to non-existent provisions in the  
15            1999 Settlement Agreement concerning the MGC, and claims that failure to honor  
16            said provisions will cause the Company harm.

17    **Q.     Are there other aspects of the 1999 Settlement Agreement that have bearing**  
18    **on this discussion?**

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<sup>3</sup> *Arizona Public Service Company v Arizona Corporation Commission*, Superior Court of the State of Arizona, Docket No. CV-2002-022232, Complaint filed November 15, 2002. See especially paragraphs 21 and 27-29. APS's Complaint was later withdrawn following resolution of a subsequent rate case.

<sup>4</sup> "...[O]ne of the reasons that we actually requested the Track A, that there be some relief from mandatory divestiture, is we came very quickly to the conclusion that mandatory divestiture would put at risk our tax-exempt financing on some of our distribution and transmission facilities, which would have driven up rates... So we went in and really asked that that not be required, that it be permissive and that it be selective." Docket No. E-01933A-05-0650, Tr. at 580. Although Mr. Pignatelli states that rates would have been driven up from loss of the tax benefit, at the time of the Track A hearing, TEP had another seven years remaining on its rate cap.

1 A. Yes. Section 3.1 of the Settlement Agreement provides that the divestiture  
2 of TEP's assets would occur at market value. Further, Decision No. 62103, which  
3 conditionally approved the Settlement Agreement, stated that the Commission  
4 reserved the right to review the appropriate market price for the assets. As the  
5 divestiture never took place, TEP is now attempting to realize market pricing  
6 without ever having transferred the assets to an entity required to purchase them  
7 at market value.

8 **Q. On page 3 of his direct testimony, Mr. Grant states that the rate freeze under**  
9 **the Settlement Agreement was agreed upon as part of a transition to market-**  
10 **based rates for generation services. Do you wish to comment on this**  
11 **statement?**

12 A. Yes. This statement gives the impression that the rate cap was tied to a  
13 transition to market rates, as if the two provisions were directly exchanged in a  
14 quid-pro-quo. Such is not the case. While any settlement agreement is most  
15 properly viewed as a "package deal," the rate cap in the Settlement Agreement  
16 was tied most prominently to the recovery of stranded cost. Indeed, the length of  
17 the rate cap was established for exactly the same length of time that TEP was  
18 permitted to recover stranded cost.

19 TEP's stranded cost was projected to be very large (\$683 million) given  
20 the size of the Company and the Settlement Agreement provided a significant  
21 benefit to TEP by resolving the stranded cost issue in a way that protected the  
22 Company's financial health. The importance of stranded cost recovery to  
23 establishing the balance of the bargain in the TEP Settlement Agreement is

1 demonstrated in Paragraph 13.1 of the Agreement, which is the first paragraph in  
2 a section entitled, "Contingencies to This Settlement Agreement":

3 13.1 Neither the Parties nor the Commission shall take any action that would  
4 diminish the recovery of TEP's stranded costs or regulatory assets provided  
5 for herein. In entering into this Settlement Agreement, TEP has relied upon  
6 the Commission's irrevocable promise to permit recovery of TEP's stranded  
7 costs and regulatory assets provided herein. Such irrevocable promise by the  
8 Commission shall be evidenced by the issuance of the Commission's  
9 Approval Order, shall survive the expiration of the Settlement Agreement and  
10 shall be specifically enforceable against this and any future Commission.  
11

12 In contrast, there is no analogous language in the Settlement Agreement  
13 assuring future "market pricing" of Standard Offer generation rates, indeed no  
14 reference to market pricing of Standard Offer generation rates at all, except as  
15 implied through the Agreement's divestiture provision.

16 **Q. On pages 5-6 of his direct testimony, Mr. Grant calculates the amount of**  
17 **TEP's proposed TCRAC based on the annual retail revenue deficiency**  
18 **claimed by TEP in the 2004 rate review docket. Do you wish to comment on**  
19 **this calculation?**

20 **A.** Yes. TEP is claiming that it has suffered revenue deficiencies stemming  
21 from its adherence to the rate cap. Mr. Grant calculates the Company's  
22 cumulative deficiency claim based on the \$111 million revenue deficiency filed  
23 by the Company for 2003 as part of its 2004 rate review, with additional  
24 deficiencies attributed to each subsequent year, plus carrying costs.

25 The \$111 million revenue deficiency claimed by the Company for 2003  
26 was not endorsed by any other party and was not approved by the Commission.  
27 The Commission merely determined that it did not have cause to *reduce* TEP's

1 rates. As pointed out in my testimony in the 2004 rate review, TEP's calculation  
2 of a \$111 million revenue deficiency relied upon an inflated fixed cost factor for  
3 Springerville Unit No. 1; failed to recognize any customer benefits from short-  
4 term wholesale sales; applied a return-on-equity that exceeded the Company's last  
5 allowed return; and employed a hypothetical capital structure that increased the  
6 equity ratio from the previously-approved hypothetical capital structure. As  
7 shown in my testimony in that docket, correction of just these four items reduced  
8 the calculated revenue deficiency from \$111 million to \$38 million.

9 Moreover, Mr. Grant calculates the "harm" to TEP starting in 2003, based  
10 on the Company's claimed revenue deficiency for the 2003 test period. However,  
11 even if the Commission were to accept TEP's claim that it is entitled to recover  
12 foregone deficiencies, the earliest time any 2003 test year deficiency would likely  
13 have been recoverable in rates would have been 2006. The Company's filing to  
14 conduct the 2004 rate review was not completed until September 15, 2004, and  
15 the direct testimony of Staff, RUCO and intervenors was not filed until June 24,  
16 2005. Had TEP's filing for test year 2003 been the basis for a rate case it is  
17 difficult to imagine new rates taking effect before 2006. Thus, Mr. Grant  
18 overstates his cumulative deficiency claim by starting to accrue it at least three  
19 years too soon.

20 Finally, TEP's claim of harm ignores the realities of the very profitable  
21 years the Company experienced throughout much of the rate cap period. Based  
22 on my review of information in the 10-K filings made by TEP and/or its parent

1 company, Unisource Energy Corporation, I have calculated that TEP has earned  
2 the following returns on common equity since 1999:

3	1999	27.20%
4	2000	17.31%
5	2001	24.12%
6	2002	15.65%
7	2003	31.75%
8	2004	11.13%
9	2005	8.64%
10	2006	12.03%

11  
12 Clearly, over the rate cap period as a whole, TEP has done very well.  
13 While the California energy crisis was thwarting the advance of Arizona's direct  
14 access implementation, TEP was profiting handsomely selling its excess  
15 generation into wholesale markets.<sup>5</sup> So while it is true that TEP has lived up to its  
16 rate cap commitments, so have customers. TEP was not asked to share the profits  
17 it earned from off-system sales by lowering its retail rates.

18 **Q. What is the revenue requirement impact of removing the TCRAC from the**  
19 **Cost-of-Service Methodology results?**

20 A. Removing the TCRAC reduces TEP's proposed revenue requirement by  
21 \$117.6 million. This is reflected by removing the TCRAC amounts shown on  
22 Schedule KCH-1, page 1, line 11.

23  
24 **B. Springerville Unit No. 1 Fixed Costs**

25 **Q. What has TEP proposed with respect to the treatment of fixed costs at the**  
26 **Springerville Unit No. 1 generation facility?**

1 A. As discussed in the direct testimony of David Hutchens, TEP is proposing  
2 to significantly increase the "fixed cost recovery rate" applied to its Springerville  
3 Unit No. 1 fixed costs.

4 **Q. What is the fixed cost recovery rate?**

5 A. The fixed cost recovery rate is a unit cost that is applied to the Company's  
6 fixed costs at the Springerville Unit No. 1 for revenue requirement purposes.  
7 Unlike traditional recovery of utility plant costs, which is achieved by earning a  
8 return on net book value of plant assets, Springerville Unit No. 1 is structured as a  
9 capital lease, the fixed costs of which are an expense.

10 The fixed cost recovery for Springerville Unit No. 1 has been governed by  
11 Commission Decision No. 56659, issued in 1989, which involves the finding of  
12 imprudence on the part of TEP management. According to that Decision, TEP  
13 came before the Commission in 1983 and requested to transfer Springerville Unit  
14 No. 1 to a newly formed subsidiary, Alamito Company ("Alamito"). The stated  
15 purpose of the transfer was to "separate TEP's wholesale and retail businesses,"  
16 although the Commission later concluded that TEP had other motives as well.<sup>6</sup>  
17 The Decision states that the agreement between TEP and Alamito provided for the  
18 sale and leaseback of Springerville Unit No. 1 at a price that exceeded the  
19 depreciated original cost by \$220 million, and that as a result, TEP was "paying  
20 lease payments which incorporate the inflated cost of Springerville Unit No. 1."<sup>7</sup>

21 The Commission ultimately concluded that TEP acted imprudently in executing

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<sup>5</sup> The Form 10-K filed by TEP for 2002 indicates that the average unit price for TEP's wholesale sales tripled between 1999 and 2001 and the Company's revenues from wholesale sales grew from \$171 million to \$734 million.

<sup>6</sup> Decision No. 56659, p. 7, lines 7-15 and lines 22-27.

1 the Springerville Unit No. 1 lease with Alamito. Among other things, the

2 Commission determined:

3 “If the spin-off had been the result of an arms length transaction, free of self-  
4 dealing, we might have accepted it. However, that was not the case. In essence,  
5 TEP continued to have all the operating risk associated with Springerville Unit  
6 No. 1 and San Juan Unit No. 3 while Alamito enjoyed all the upside potential of  
7 selling the two plants at a gain. It was clearly an imprudent business decision to  
8 spin-off Alamito without amending the twelve-year Power Sale Agreement. In  
9 order to make ratepayers whole for this imprudence, the capacity purchased from  
10 Alamito should be priced at a level that prudent management could have  
11 obtained.” [Emphasis in original.]<sup>8</sup>

12  
13 Consistent with this determination, the Commission ordered a fixed cost recovery  
14 rate for Springerville Unit No. 1 of \$15 per kW-month, based on Staff testimony  
15 that this represented a reasonable purchase price for the capacity.

16 **Q. Does the Decision No. 56659 indicate that the Commission was adopting a**  
17 **policy of recovering Springerville Unit No. 1 fixed costs at “market” rates as**  
18 **a matter of philosophy?**

19 A. No. The Decision does not even mention the word “market” in reaching its  
20 determination regarding the recovery of Springerville Unit No. 1 fixed costs. The  
21 Commission stated that it was attempting to make ratepayers whole for the  
22 imprudent business decision of management. To do so, it needed an appropriate  
23 benchmark for establishing Springerville Unit No. 1 fixed costs.

24 **Q. What is the current cost of the lease payment for Springerville Unit No. 1?**

25 A. According to the Company’s workpapers, TEP’s annual capital lease  
26 obligation for Springerville Unit No. 1 for 2006 is \$61.9 million. For 380

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<sup>7</sup> Ibid., p. 9, line 20 – p. 10, line 1.

<sup>8</sup> Ibid., p. 11, lines 1-11.

1 megawatts of capacity, this translates into a lease obligation of \$13.57 per kW-  
2 month.

3 In addition, according to TEP's workpapers, the sum of the capital lease,  
4 O&M, and administrative and general costs for Springerville Unit No. 1 is \$85  
5 million in the 2006 test year. This yields fixed cost recovery rate of \$18.63 per  
6 kW-month for the test year.<sup>9</sup>

7 **Q. What new fixed cost recovery rate has Mr. Hutchens proposed?**

8 A. Mr. Hutchens has proposed a fixed cost recovery rate of \$25.67 per-kW-  
9 month, which is a 71 percent increase over the current fixed cost recovery rate of  
10 \$15 per kW-month, and 38 percent greater than the fixed cost recovery rate for  
11 Springerville Unit No. 1 in the test year.

12 **Q. What is the basis of Mr. Hutchens' recommendation?**

13 A. Mr. Hutchens asserts that because the initial fixed cost factor of \$15 per  
14 kW-month was based on the market value of capacity at the time of Decision No.  
15 56659, the fixed cost recovery rate should be adjusted to reflect purportedly  
16 higher market values for long-term capacity at this time. Mr. Hutchens proposes  
17 to impute a price for capacity based on the difference between the hypothetical  
18 wholesale market revenues that Springerville Unit No. 1 could have received by  
19 selling its output into the wholesale market and its variable production costs. In  
20 essence, TEP is proposing that it be rewarded by having customers pay it for  
21 Springerville Unit No. 1 based on a seller's ability to mark up the price of power  
22 from the facility over its variable cost of production.

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<sup>9</sup> TEP workpaper (0402)002628.

1   **Q.     What is your assessment of this proposal?**

2   A.           I recommend that the Company's proposal be rejected. It is critical to bear  
3           in mind several points here:

4           (1) The current fixed cost recovery rate of \$15 per kW-month was determined in  
5           connection with the Commission's finding of imprudence on TEP's part. The  
6           Commission's use of an alternative value for capacity, in lieu of cost, was not a  
7           reward to the Company, but a penalty exacted for poor judgment on  
8           management's part. That decision established a cost recovery factor based on a  
9           proxy for purchased capacity, not a market-based system of recovering costs.

10          Increasing the fixed cost recovery factor today by 71 percent, based on an  
11          assertion of higher market prices for capacity, misapplies the principle adopted in  
12          1989, and would represent an undue reward for the Company's imprudence in the  
13          1980s.

14          (2) In utility ratemaking, a portion of the fixed plant costs associated with a given  
15          generation unit generally *decline* over time, as the unit is depreciated.

16          Springerville Unit No. 1 unit is over 20 years old, and but for TEP's choice of  
17          financing arrangement, its fixed costs would reflect significant depreciation under  
18          traditional ratemaking practice. In light of this fact, a request to increase fixed  
19          cost recovery by 71 percent as proposed by Mr. Hutchens is unreasonable.

20          (3) The proposed fixed cost recovery rate of \$25.67 per kW-month is well in  
21          excess of the fixed cost recovery rate for Springerville Unit No. 1 of \$18.63 per  
22          kW-month for the test year. Given that the Springerville Unit No. 1 lease cost was  
23          found to be imprudent by the Commission in 1989, the test year fixed cost

1 associated with operating under the current lease arrangement should represent  
2 the maximum level of fixed cost charged to ratepayers in this proceeding. The  
3 Commission should certainly not adopt a fixed cost recovery rate in excess of  
4 TEP's test year expense, as that would perversely reward TEP management for its  
5 past decisions that were found to be imprudent.

6 **Q. What do you recommend as an alternative to TEP's proposal?**

7 A. I recommend that Springerville Unit No. 1 fixed costs be based on the  
8 fixed cost recovery rate of \$18.63 per kW-month incurred by TEP in the test year.  
9 While it could reasonably be argued that the \$15 per kW-month fixed cost  
10 recovery rate established in Decision No. 56659 should be retained, I would  
11 support allowing TEP to recover its test year fixed cost recovery rate for this  
12 facility.

13 **Q. What are the revenue implications of accepting your recommendation?**

14 A. My recommendation reduces TEP's proposed revenue requirements by  
15 \$30.5 million per year, as shown in Schedule KCH-2.

16  
17 **C. Margins from Short Term Sales**

18 **Q. What has TEP proposed with respect to the treatment of off-system sales**  
19 **margins from short-term sales?**

20 A. As explained in the direct testimony of Mr. Hutchens, TEP is proposing to  
21 remove all margins from short-term off-system sales in base rates. Instead, TEP is  
22 proposing that part of the benefit from short-term sales be passed on to customers  
23 through the Company's proposed purchased power and fuel adjustment clause

1 ("PPFAC"). The sharing mechanism proposed by TEP for short-term sales is  
2 highly unusual in that customers would receive 90 percent of the off-system sales  
3 revenues in the PPFAC, but would be responsible for 100 percent of the fuel costs  
4 necessary to make such sales.

5 **Q. What is your assessment of TEP's proposed treatment of the benefits from**  
6 **short-term sales?**

7 A. The Company's proposed approach is unreasonable and should be  
8 rejected. There are two distinct aspects of this issue that must be addressed: (1)  
9 the Company's removal of short-term sales margins from the determination of  
10 base rates; and (2) the application of short-term sales margins to the proposed  
11 PPFAC.

12 **Q. Please elaborate on the first aspect you wish to address, TEP's removal of**  
13 **short-term sales margins from base rates.**

14 A. TEP reports \$77.7 million in short-term sales revenue in the test year. The  
15 fuel and purchased power costs needed to support these sales is \$52.4 million,  
16 producing short-term sales margins of \$25.3 million. In preparing its rate filing,  
17 TEP has removed all short-term sales revenues and costs (and thus, margins) from  
18 the determination of the revenue requirement. Instead, all short-term sales  
19 revenues are proposed to be treated prospectively pursuant to the Company's  
20 proposed PPFAC.

21 In my opinion, this proposed treatment is entirely unjustified. The short-  
22 term sales in question are made with assets that are included in rate base, the full  
23 cost of which is allocated to customers. Consequently, the full value of the test-

1 year benefit of these sales should be reflected as a credit to customers against base  
2 rates. This means that if the Commission accepts TEP's proposal to set the Base  
3 Cost of Fuel and Purchased Power based on a 2009 forecast, then this Base Cost  
4 of Fuel and Purchased Power should reflect a credit to customers equal to 100  
5 percent of the margin from short-term sales for the test-year. Failure to credit  
6 customers with 100 percent of the test year margin will simply create a "hidden"  
7 supplement to the Company's ROE approved in this proceeding.

8 **Q. Please explain this last point.**

9 A. The fundamental objective of a rate case is to set rates that provide the  
10 utility an opportunity to earn its allowed rate of return. Short-term sales margins  
11 are net revenues to the utility; consequently, they have a direct impact on the  
12 utility's return. When we refer to "crediting" customers with short-term sales  
13 margins when setting base rates, we are simply recognizing that these net  
14 revenues contribute to the utility's net income. By recognizing these net revenues  
15 in the determination of the rates needed to reach the targeted rate-of-return, there  
16 is a dollar-for-dollar reduction in the revenues necessary to collect from  
17 customers in order to reach that return, giving rise to the notion of a revenue  
18 "credit" to customers.

19 Once rates are set, utilities have the incentive to maximize their short-term  
20 sales margins, as these margins flow to their respective bottom lines, enhancing  
21 their returns. In the case at hand, TEP has proposed that 10 percent of short-term  
22 revenues be retained by the Company in its PPFAC. If the test year margin from  
23 short-term sales is not fully credited to customers when base rates are set, then

1       this margin will be excluded from the revenues that are recognized in producing  
2       the targeted rate of return. Then, to the extent that any short-term sales margins  
3       are actually realized, the revenues retained by the Company will produce a  
4       supplement to the allowed rate-of-return. Put yet another way, TEP's attempt to  
5       exclude all short-term sales margins from base rates, combined with its proposal  
6       to credit 10 percent of the short-term sales revenues to shareholders, is simply a  
7       thinly-veiled request for a higher return on equity than the 10.75 percent  
8       recommended by TEP witness Samuel C. Hadaway. In my opinion, this approach  
9       results in an unjustified transfer payment from customers to shareholders.

10   **Q.   How do you respond to the claim that sharing revenues with the Company**  
11   **provides an incentive to make profitable short-term sales?**

12   A       I will address TEP's proposal for shareholders to retain 10 percent of  
13   short-term sales revenues in the PPFAC in Section V of my testimony. At this  
14   juncture, I will make the preliminary comment that sharing short-term revenues  
15   without also sharing the costs of making these sales is entirely inappropriate. I  
16   agree, however, that sharing short-term sales margins with the Company can  
17   provide an appropriate incentive to make increased short-term sales above the  
18   level expected for the test year. But this argument has no relevance for the  
19   treatment of short-term sales margins in the establishment of base rates. If test  
20   year margins are fully credited to customers in base rates, any failure by the  
21   Company to achieve this margin will impact its bottom line. Consequently,  
22   removing test year margins from base rates provides absolutely no additional  
23   incentive for the utility to make short-term sales; as I stated, failure to credit

1 customers with 100 percent of the short-term margins would provide nothing  
2 except a supplement to the Company's allowed ROE.

3 **Q. What are the revenue implications of accepting your recommendation to**  
4 **credit 100 percent of short-term sales margins against base rates?**

5 A. My recommendation reduces TEP's proposed revenue requirements by  
6 \$24.0 million per year, as shown in Schedule KCH-3.

7  
8 **D. Sundt and San Juan Coal Contract Buyouts**

9 **Q. What has TEP proposed with respect to the recovery of costs associated with**  
10 **coal contract buyouts?**

11 A. As explained by Mr. Hutchens, in 2002, TEP terminated a long-term  
12 contract for coal supplied to its Sundt Station. The Company paid \$11.25 million  
13 to buy out the agreement.<sup>10</sup>

14 In addition, Mr. Hutchens explains that in December 2002, in connection  
15 with the negotiation of a new underground coal supply agreement, TEP paid San  
16 Juan Coal Company \$15.4 million in compensation for stranded surface  
17 operations that were no longer needed to supply coal to the San Juan Station.<sup>11</sup>

18 Mr. Hutchens testifies that each of these buyouts was less expensive than  
19 the alternatives that were available to the Company, given the contracts that were  
20 in place.

21 TEP is proposing that the cost of each of these buyouts be recognized as a  
22 regulatory asset in rate base and that these costs be recovered from ratepayers.

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<sup>10</sup> Direct testimony of David G. Hutchens, p.26, line 22 - p.27, line 2.

<sup>11</sup> Ibid., p. 27, line 18 - p. 28, line 8.

1 The regulatory assets would be amortized over four years starting in the rate  
2 effective period, and would earn a return.

3 **Q. What is your assessment of TEP's proposed treatment of the Sundt and San**  
4 **Juan coal buyouts?**

5 A. Both buyouts appear to be prudent, but there are serious questions with  
6 respect to timing. Both buyouts occurred well before the test year, and each is a  
7 non-recurring expense. As such, there is a strong presumption against inclusion of  
8 recovery of such costs in rates going forward. Moreover, I am not aware of any  
9 deferred accounting order that recognizes these costs as deferred expenses.

10 On the other hand, both buyouts appear to result in cost avoidance going  
11 forward, which will provide a future benefit to customers. At the same time, TEP  
12 has benefited directly from the cost avoidance attributable to the buyouts since the  
13 time they were consummated in 2002.

14 In my opinion, the most reasonable approach to balance the interests of  
15 TEP and customers in this situation is to recognize regulatory assets for the  
16 respective buyouts, but to initiate the amortization periods at the time the buyouts  
17 occurred, 2002. This is appropriate as TEP shareholders have benefited since  
18 2002 from the avoided costs attributable to the buyouts. At the same time,  
19 because the buyouts will provide cost avoidance over an extended period of time,  
20 the amortization periods should be extended from the four year period proposed  
21 by TEP to a ten-year period. TEP should be allowed to earn a return on the  
22 regulatory assets, but only on the regulatory asset balance remaining at the end of  
23 the test year, i.e., after recognizing amortization starting in 2002.

1   **Q.     What are the revenue implications of accepting your recommendation with**  
2       **respect to the treatment of the Sundt and San Juan coal buyouts?**

3   A.       My recommendation reduces TEP's proposed revenue requirements by  
4       \$5.5 million per year, as shown in Schedule KCH-4.

5  
6       **E.   Luna Energy Facility**

7   **Q.     What has TEP proposed with respect to the treatment of costs for the Luna**  
8       **Energy Facility in its Cost-of-Service Methodology proposal?**

9   A.       The 570-MW Luna Energy Facility is located near Deming, New Mexico,  
10       and was purchased from Duke Energy by TEP and two other parties in November  
11       2004. According to announcements in the trade press at the time, the plant was  
12       purchased for a reported \$40 million, and was 48% complete at the time of  
13       purchase. Reportedly, an additional \$110 million was needed to complete  
14       construction. The facility came on line April 4, 2006.

15           TEP's ownership share of the facility is 190 MW. According to TEP's  
16       Cost-of-Service Methodology proposal, the Company is proposing to recover the  
17       fixed costs of this facility through a "market-based capacity charge." TEP  
18       proposes this approach in lieu of seeking to earn a return on the net book value of  
19       the plant and to recover test year fixed O&M costs. Consequently, TEP has  
20       removed the Luna Energy Facility from net plant in service for ratemaking  
21       purposes, and substituted a \$7.00 per kW-month capacity charge. My analysis in  
22       Schedule KCH-5 shows that TEP's proposed approach is more expensive for  
23       customers than traditional cost-based recovery.

1   **Q.     What is your assessment of this proposal?**

2   A.           I recommend against adoption of the Company's proposed treatment of  
3       Luna-related fixed costs. TEP is seeking to obligate customers to purchase the  
4       capacity and energy of this plant, but is seeking to price the capacity at an  
5       estimated market value rather than the actual cost to TEP of the investment and its  
6       operating expenses. I do not believe such an approach is consistent with a cost-of-  
7       service methodology.

8   **Q.     What alternative ratemaking treatment do you recommend for the Luna**  
9       **Energy Facility?**

10  A.           If customers are going to be responsible for the recovery of Luna Energy  
11       Facility costs, then the recovery of fixed costs should be based on inclusion of the  
12       facility's net plant in service in rate base, and recovery of fixed O&M costs based  
13       on test year pro-forma expenses.

14  **Q.     What are the revenue implications of accepting your recommendation with**  
15       **respect to the fixed cost recovery of the Luna Energy Facility based on its net**  
16       **book value and test year pro-forma expenses?**

17  A.           My recommendation reduces TEP's proposed revenue requirements by  
18       \$6.7 million per year, as shown in Schedule KCH-5.

19

20  **V.     Purchased Power and Fuel Adjustment Clause**

21  **Q.     What has TEP proposed with respect to a Purchased Power and Fuel**  
22       **Adjustment Clause?**

1 A. As explained in the direct testimony of Mr. Pignatelli and Mr. Hutchens,  
2 TEP is seeking approval of a PPFAC that would provide recovery (or return) of  
3 100 percent of the difference between the actual cost of fuel and purchased power  
4 and the Base Cost of Fuel and Purchased Power.<sup>12</sup> TEP proposes that the Base  
5 Cost of Fuel and Purchased Power in this proceeding be established using a 2009  
6 forecast, and that, consequently, the PPFAC rate be set at zero for 2009. The  
7 PPFAC rate for 2010 would be comprised of two components: (1) a Forward  
8 Component, which would be set equal to the difference between the projected fuel  
9 cost in 2010 and the Base Cost of Fuel and Purchased Power (previously  
10 established for 2009); and (2) a True-Up Component, which would correct for  
11 over- or under-recovery of actual costs from the prior year.

12 In addition to providing for recovery of 100 percent of the difference  
13 between the actual cost of fuel and purchased power and the Base Cost of Fuel  
14 and Purchased Power, TEP is proposing that 90 percent of the revenues (and 100  
15 percent of the costs) of short-term sales be included in the PPFAC rate.

16 **Q. What general observations do you have regarding fuel adjustment clauses?**

17 A. A fuel adjustment clause calls out specific expenses for recovery that are  
18 not included in rates when rates are set pursuant to a general rate proceeding. As  
19 such, it is a form of single-issue ratemaking, and should only be applied after  
20 carefully weighing the justification for such an approach against its several  
21 drawbacks.

22 **Q. What is single-issue ratemaking?**

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<sup>12</sup> For ease of exposition, I will occasionally refer to Base Cost of Fuel and Purchased Power simply as "Base Cost".

1 A. Single-issue ratemaking occurs when utility rates are adjusted in response  
2 to a change in a single cost item considered in isolation. Single-issue ratemaking  
3 ignores the multitude of other factors that otherwise influence rates, some of  
4 which could, if properly considered, move rates in the opposite direction from the  
5 single-issue change.

6 Setting rates based on a change in a single cost item runs contrary to the  
7 basic principles of traditional utility regulation. When regulatory commissions  
8 determine the appropriateness of a rate or charge that a utility seeks to impose on  
9 its customers, the standard practice is to review and consider all relevant factors,  
10 rather than just a single factor. To consider some costs in isolation might cause a  
11 commission to allow a utility to increase rates to recover higher costs in one area  
12 without recognizing counterbalancing savings in another area. For these reasons,  
13 single-issue ratemaking, absent a compelling public interest, is generally not  
14 sound regulatory practice. I acknowledge, however, that the most frequently-  
15 accepted form of single-issue ratemaking is a fuel adjustment clause, such as that  
16 requested by TEP.

17 **Q. Do you have any other general observations regarding fuel adjustment**  
18 **clauses?**

19 A. Yes. Because these mechanisms simply pass through changes in cost to  
20 customers, there is a valid concern that adoption of a fuel adjustment clause  
21 would reduce a utility's incentive to manage its costs as well as it would manage  
22 them if the utility remained fully responsible for the cost risk. This reduced  
23 incentive to manage costs is another important reason for a regulatory

1 commission to proceed with great caution before adopting a fuel adjustment  
2 clause.

3 **Q. In your experience, do utilities tend to dispute the argument that fuel**  
4 **adjustment clauses reduce a utility's incentive to manage its costs?**

5 A. Yes. It is not unusual for utility management to argue that the adoption of  
6 a fuel adjustment clause would not reduce its incentive to manage costs  
7 effectively, and Mr. Hutchens makes such an argument on TEP's behalf in this  
8 case. Yet, at the same time, utilities, including TEP, often assert that they should  
9 share in the benefit of short-term sales, in order to provide a proper incentive to  
10 engage in such transactions. I submit that these positions are inconsistent. If it is  
11 true that a particular organization requires a financial incentive in order to  
12 maximize its off-system sales revenues for the benefit of its customers, then it is  
13 likely also to be true that the same organization requires a financial incentive to  
14 reasonably minimize its power costs for the benefit of its customers.

15 **Q. In light of the concerns you have identified with respect to single-issue**  
16 **ratemaking and reduced incentive to manage costs, what factors should a**  
17 **commission consider if it is asked to approve a fuel adjustment clause?**

18 A. Commissions should consider three basic questions before adopting a fuel  
19 adjustment clause:

- 20 1. Are the costs that would be recovered through a fuel adjustment clause  
21 subject to significant volatility from year to year?
- 22 2. Are the costs in question largely beyond the control of management?
- 23 3. Are the costs that could be recovered through a fuel adjustment clause  
24 substantial enough to have a material impact on the utility's revenue  
25 requirement and financial health between rate cases if they were to go  
26 unrecovered?  
27

1    **Q.     Does TEP address these three basic questions in its proposal for a PPFAC?**

2    A.           TEP addresses these questions in a general way, noting for example, the  
3           Company's increasing reliance on natural gas as a fuel. At the same time, TEP  
4           does not present a great deal of quantitative analysis addressing its financial  
5           exposure to fuel price volatility.

6    **Q.     What is your assessment of TEP's PPFAC proposal?**

7    A.           I am neither recommending for nor against adoption of a PPFAC for TEP.  
8           In my opinion, TEP has not produced compelling quantitative evidence  
9           demonstrating its financial exposure to fuel volatility. At the same time, I am  
10          aware of the significant exposure to fuel volatility faced by the other major  
11          jurisdictional utility, APS, and acknowledge the possibility that TEP may also  
12          face material exposure in this regard.

13   **Q.     If a PPFAC is adopted, do you recommend any changes to the proposal put**  
14   **forward by TEP?**

15   A.           Yes. If a PPFAC is adopted, then I recommend the following  
16          modifications to the structure proposed by TEP:

17          1. As I discussed in the previous section of my testimony, the Base Cost of Fuel  
18          and Purchased Power should include a credit to customers for 100 percent of the  
19          margins from off-system sales during the test year. (In contrast, TEP's proposal  
20          excludes all short-term sales margins from the Base Cost of Fuel and Purchased  
21          Power.)

22          2. Rather than setting each year's fuel and purchased power recovery based on a  
23          forecast, as TEP proposes, the PPFAC rate should simply recover the difference

1 between actual purchased power and fuel costs and the Base Cost of Fuel and  
2 Purchased Power. (In other words, the Forward Component should be eliminated  
3 from the calculation of the PPFAC rate.)

4 3. To maintain incentives for the utility to manage its costs effectively,  
5 responsibility for changes in fuel and purchased power costs should be shared  
6 between the utility and customers. I recommend a 90/10 sharing between  
7 customers and TEP.

8 4. The same 90/10 sharing percentage used for fuel and purchased power should  
9 be applied to changes in off-system sales margins (relative to the margins  
10 included in the Base Cost of Fuel and Purchased Power).

11 5. The PPFAC rate charged to customers should be differentiated by voltage level  
12 to properly reflect line loss differences among customers taking service at  
13 different voltage levels.

14 **Q. Why should the Base Cost of Fuel and Purchased Power reflect 100 percent**  
15 **of the margins from short-term sales?**

16 A. The Base Cost of Fuel and Purchased Power is the starting point for  
17 calculating the PPFAC rate. As such, it should reflect the net cost of fuel and  
18 purchased power established for the base period, including all margins from short-  
19 term sales. Short-term sales are made with assets that are included in rate base, the  
20 full cost of which is allocated to customers. Consequently, the full value of the  
21 test-year benefit of these sales should be reflected as a credit against customer  
22 base rates.

1 **Q. Have you calculated an adjustment to the Base Cost of Fuel and Purchased**  
2 **Power calculated by TEP?**

3 A. Yes. TEP Exhibit DGH-8 presents the Company's initial projection of the  
4 Base Cost of Fuel and Purchased Power. In Schedule KCH-6, I adjust TEP's  
5 calculation to: (1) included short-term sales margins in the Base Cost of Fuel and  
6 Purchased Power; and (2) remove the "market-based capacity charge" proposed  
7 by TEP for the Luna Energy Facility (discussed in Section IV of my testimony).  
8 These two adjustments reduce the projected Base Cost of Fuel and Purchased  
9 Power from 3.30 cents/kWh to 2.88 cents/kWh.

10 **Q. Why should the Forward Component be eliminated from the calculation of**  
11 **the PPFAC rate?**

12 A. According to the approach proposed by TEP, fuel and purchased power  
13 costs in rates would always be based on a forecast. In my view, it is not necessary  
14 or desirable to introduce this level of conjecture into the rate setting process each  
15 year. The primary objective of a PPFAC is to protect the utility from fuel and  
16 purchased power price volatility. That objective is fully accomplished using an  
17 approach that simply recovers the difference between actual costs and Base Costs,  
18 applying an after-the-fact calculation.

19 **Q Why should responsibility for fuel and purchased power costs above (or**  
20 **below) Base Costs be shared between TEP and its customers?**

21 A A sharing mechanism is an effective means for addressing the disincentive  
22 for effective cost management that is otherwise introduced with a fuel adjustment  
23 clause. A pass-through of 100 percent of costs dulls the utility's incentive to

1 manage its costs effectively. Some cost-sharing responsibility maintains that  
2 incentive. The 90/10 sharing approach I am recommending strikes a balance  
3 between protecting the utility's financial health, while also providing for  
4 appropriate incentives.

5 **Q. What is your assessment of TEP's proposal to retain 10 percent of the**  
6 **revenues from short-term sales for shareholders?**

7 A. The Company's proposal would have customers be responsible for 100  
8 percent of the costs of generating off-system sales while reserving 10 percent of  
9 the revenues to shareholders. Such an asymmetrical approach is inherently  
10 unreasonable. Customers should not pay for energy used to make short-term sales  
11 if the revenue from those sales is credited to shareholders.

12 **Q. If the proposed PPFAC is adopted, what is the proper approach to sharing**  
13 **short-term sales margins?**

14 A. I believe there should be consistent treatment between the sharing  
15 mechanism (or lack thereof) applied to deviations in fuel and purchased power  
16 expense and the sharing mechanism (or lack thereof) applied to deviations in  
17 short-term sales margins. Philosophically, I support approaches that provide direct  
18 incentives both for reasonably minimizing energy costs and for maximizing short-  
19 term sales margins. This occurs under traditional regulation with no fuel  
20 adjustment clause and with 100 percent retention by the utility of increases in  
21 short-term sales margins above the level in base rates. It can also occur if a  
22 PPFAC is adopted, and a consistent sharing arrangement between customers and  
23 the utility is adopted, e.g., a 90/10 customer-to-shareholder split is adopted both

1 for deviations in fuel and purchased power expense as well as for changes in  
2 short-term sales margins. For this reason, I am recommending that if a PPFAC is  
3 adopted, changes in short-term sales margins (relative to Base Cost) should be  
4 split 90/10 between customers and TEP.

5 At the same time, if the proposed PPFAC is adopted and it contains no  
6 sharing between customers and shareholders for fuel and purchased power  
7 expense, then neither should there be any sharing of changes in short-term sales  
8 margins. In such a case, 100 percent of any increase in short-term sales margins  
9 should flow through the fuel adjustor mechanism to the benefit of customers.

10 **Q. Why should the PPFAC rate be differentiated by voltage levels?**

11 A. A fuel adjustment charge should be differentiated by voltage for the same  
12 reasons that base rates reflect voltage differences: customers taking service at  
13 higher voltages incur fewer line losses. Consequently, higher voltage customers  
14 require fewer kilowatt-hours of generation to meet a given level of energy  
15 consumption delivered to their meters. The PPFAC rates for customers should be  
16 designed to reflect these line loss differences.

17  
18 **VI. True-Up Revenues**

19 **Q. What does Decision No. 69568 require with respect to the treatment of True-**  
20 **Up Revenues?**

21 A. As discussed in Section IV of my testimony, in Decision No. 69568, the  
22 Commission determined that rates will not be reduced by the amount of the Fixed  
23 CTC at such time that \$450 million in stranded cost is recovered, as originally

1 intended. Instead, the Decision provided that TEP customers should be protected  
2 by providing for a mechanism to refund or credit the revenues, plus interest, that  
3 will continue to be collected by the modified treatment of the Fixed CTC, until  
4 new rates are approved. These revenues are called True-Up Revenues. TEP  
5 estimates that approximately \$66 million of True-Up Revenues will be collected  
6 between May 2008 and December 31, 2008.<sup>13</sup>

7 **Q. How has TEP proposed to treat the True-Up Revenues?**

8 A. As explained by Mr. Grant, if the Market Methodology is adopted, then  
9 TEP proposes to refund the full amount of True-Up Revenues, plus interest equal  
10 to TEP's cost of short-term debt, over a twelve-month period. If the Hybrid  
11 Methodology is chosen, TEP proposes that shareholders retain the True-Up  
12 Revenues, as part of the "compromise" between the Cost-of-Service and Market  
13 Methodologies that the Hybrid Methodology is intended to represent. If the Cost-  
14 of-Service Methodology is selected, then TEP similarly seeks to retain the True-  
15 Up Revenues, but on the grounds that the \$788 million TCRAC regulatory asset  
16 claimed by TEP already reflects a reduction of \$133 million from what TEP could  
17 otherwise claim.<sup>14</sup>

18 **Q. What is your assessment of TEP's proposed treatment of True-Up Revenues?**

19 A. I agree that if the Market Methodology is chosen, then the True-Up  
20 Revenues should be refunded over a twelve-month period. However, the rate of  
21 interest applied should be equal to the rate at which TEP earns on its regulatory

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<sup>13</sup> Direct testimony of Kentton C. Grant, p. 11, line 23 - p. 12, line 1.

<sup>14</sup> Ibid., p. 11, line 19 - p. 13, line 20.

1 assets. I disagree with TEP's proposed treatment of True-Up Revenues under the  
2 Hybrid Methodology and Cost-of-Service Methodology.

3 **Q. What is your proposed treatment of True-Up Revenues if the Hybrid**  
4 **Methodology is chosen?**

5 A. I will discuss the Hybrid Methodology further in the next section of my  
6 testimony. If this approach is chosen, it will convey a significant benefit to TEP.  
7 In such a case, most reasonable treatment of the True-Up Revenues is identical to  
8 my recommendation if the Market Methodology is chosen: the True-Up Revenues  
9 should be refunded to customers over a twelve-month period, and the rate of  
10 interest on this regulatory liability should be equal to the rate at which TEP earns  
11 on its regulatory assets.

12 **Q. What is your proposed treatment of True-Up Revenues if the Cost-of-Service**  
13 **Methodology is chosen?**

14 A. The True-Up Revenues represent a rate reduction to which customers are  
15 entitled by the terms of the 1999 Settlement Agreement. Strictly speaking, these  
16 revenues should be applied to the benefit of customers under any scenario.

17 If a PPFAC is adopted, then I recommend that the True-Up Revenues be  
18 applied as a credit against future PPFAC balances. These revenues should earn  
19 interest at the interest rate approved for PPFAC balances.

20 If a PPFAC is not adopted, then I recommend that the True-Up Revenues  
21 be returned to customers over a three-year period, and earn interest at the rate  
22 applied to TEP's regulatory asset balances.

1           These two alternative recommendations assume that TEP's proposed  
2           TCRAC is rejected by the Commission. If, for some reason, the TCRAC is  
3           adopted in whole or in part, then the True-Up Revenues should be applied against  
4           the TCRAC balance.

5   **Q.   Do you have any other comments regarding the True-Up Revenues?**

6   A.           Although the True-Up Revenues properly belong to customers, AECC  
7           would be willing to accept a resolution in which the True-Up Revenues were not  
8           returned to customers under the Cost-of-Service Methodology, if, and only if, this  
9           concession were accompanied by TEP's withdrawal of all claims that the  
10          Company would be harmed by setting rates at cost-of-service. Absent such action  
11          by TEP, the True-Up Revenues should be returned in full to customers.

12  
13   **VII.   Hybrid Methodology**

14   **Q.   What has TEP proposed with respect to the Hybrid Methodology?**

15   A.           The Hybrid Methodology is offered by TEP as a middle ground between  
16           its Cost-of-Service Methodology and Market Methodology. For the most part,  
17           rates would be set in the same manner as in the Cost-of-Service Methodology,  
18           except that certain generation assets would be excluded from rate base. Energy  
19           from these excluded facilities would be sold to TEP retail customers at market  
20           prices. The excluded facilities would be: (1) TEP's interest in the Navajo  
21           Generating Stations Units 1, 2, and 3; and (2) TEP's interest in the Four Corners  
22           Generating Stations Units 4 and 5. There would be a PPFAC as part of the Hybrid  
23           Methodology and TEP is willing to continue direct access service to customers

1 with loads of 3 MW or greater. There would be no TCRAC under the Hybrid  
2 Methodology.

3 **Q. What is your assessment of TEP's Hybrid Methodology proposal?**

4 A. TEP's Hybrid Methodology proposal is more expensive for customers  
5 than the Cost-of-Service Methodology without the TCRAC. At the same time, the  
6 impact is less extreme than either the Company's Market Methodology proposal  
7 or its Cost-of-Service/TCRAC proposal. However, the Hybrid Methodology  
8 proposal is still founded on the premise that TEP is entitled to set rates based on  
9 the MGC, a premise that is without foundation.

10 If the Commission (correctly) concludes that: (1) TEP has no basis to  
11 claim that Standard Offer generation rates are to be set equal to the MGC; and (2)  
12 the Track A Decision is res judicata, then there is no reason to entertain the  
13 Hybrid Methodology any further. Rates would properly be set based on the Cost-  
14 of-Service Methodology without the TCRAC. As discussed above, this is my  
15 recommendation. However, if the Commission disagrees with my  
16 recommendation, then the Hybrid Methodology should be considered, as it is less  
17 expensive to customers than either of the alternative proposals as advanced by  
18 TEP.

19 **Q. Are the revenue requirement adjustments you recommended for TEP's Cost-**  
20 **of-Service Methodology applicable to the Hybrid Methodology?**

21 A. Yes, with the exception of my adjustment to TEP's proposed TCRAC (as  
22 the TCRAC is not included in the Hybrid Methodology). Therefore, if the Hybrid  
23 Methodology is chosen by the Commission, then I recommend that the

1 Commission also accept each of my proposed revenue requirement adjustments  
2 presented in Section IV of my testimony, with the exception of my TCRAC  
3 adjustment.

4  
5 **VIII. Direct Access Issues**

6 **Q. Do you have any comments with respect to direct access issues in this**  
7 **proceeding?**

8 A. Yes. TEP's proposals for its Cost-of-Service Methodology and Hybrid  
9 Methodology include changes proposed by the Company with respect to direct  
10 access rights, namely, that direct access rights for customers be eliminated in the  
11 former case and restricted to customers 3 MW and greater in the latter case. I  
12 recommend that the Commission reject both of those proposed restrictions.  
13 Direct access is a statewide issue. Standard offer generation service in both the  
14 APS and SRP service territories is based on cost-of-service, and customers in  
15 those territories have not been forced to relinquish their rights to direct access. In  
16 fact, APS's generation rates have been designed specifically to avoid prejudicing  
17 the direct access decision for customers. If issues of direct access are to be  
18 addressed, it should occur in its own docket. Customer direct access rights should  
19 not be rolled back piecemeal as part of this proceeding.

20  
21 **Q. Does this conclude your direct testimony with respect to revenue**  
22 **requirement?**

23 A. Yes, it does.

**KEVIN C. HIGGINS**  
**Principal, Energy Strategies, L.L.C.**  
**215 South State St., Suite 200, Salt Lake City, UT 84111**

**Vitae**

**PROFESSIONAL EXPERIENCE**

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over \$300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

## **EDUCATION**

Ph.D. Candidate, Economics, University of Utah (coursework and field exams completed, 1981).

Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

## **SCHOLARSHIPS AND FELLOWSHIPS**

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.

Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.

Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.

New York State Regents Scholar, 1972 to 1976.

## EXPERT TESTIMONY

“Commonwealth Edison Company Proposed General Increase in Electric Rates,” **Illinois** Commerce Commission, Docket No. 07-0566. Direct testimony submitted February 11, 2008.

“In the Matter of the Application of Questar Gas Company to File a General Rate Case,” **Utah** Public Service Commission, Docket No. 07-057-13, Direct testimony submitted January 28, 2008 (test period). Cross examined February 8, 2008 (test period).

“In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately \$161.2 Million Per Year, and for Approval of a New Large Load Surcharge,” **Utah** Public Service Commission, Docket No. 07-035-93. Direct testimony submitted January 25, 2008 (test period). Cross examined February 7, 2008 (test period).

“In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices and for Tariff Approvals,” Public Utilities Commission of **Ohio**, Case Nos. 07-551-EL-AIR, 07-552-EL-ATA, 07-553-EL-AAM, and 07-554-EL-UNC. Direct testimony submitted January 10, 2008.

“In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming, Consisting of a General Rate Increase of Approximately \$36.1 Million per Year, and for Approval of a New Renewable Resource Mechanism and Marginal Cost Pricing Tariff,” **Wyoming** Public Service Commission, Docket No. 20000-277-ER-07. Direct testimony submitted January 7, 2008.

“In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service to Electric Customers in the State of Idaho,” **Idaho** Public Utilities Commission, Case No. IPC-E-07-8. Direct testimony submitted December 10, 2007. Cross examined January 23, 2008.

“In The Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution Of Electricity and Other Relief,” **Michigan** Public Service Commission, Case No. U-15245. Direct testimony submitted November 6, 2007. Rebuttal testimony submitted November 20, 2007.

“In the Matter of Montana-Dakota Utilities Co., Application for Authority to Establish Increased Rates for Electric Service,” **Montana** Public Service Commission, Docket No. D2007.7.79. Direct testimony submitted October 24, 2007.

"In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 334," **New Mexico** Public Regulation Commission, Case No. 07-0077-UT. Direct testimony submitted October 22, 2007. Rebuttal testimony submitted November 19, 2007. Cross examined December 12, 2007.

"In The Matter of Georgia Power Company's 2007 Rate Case," **Georgia** Public Service Commission, Docket No. 25060-U. Direct testimony submitted October 22, 2007. Cross examined November 7, 2007.

"In the Matter of the Application of Rocky Mountain Power for an Accounting Order to Defer the Costs Related to the MidAmerican Energy Holdings Company Transaction," **Utah** Public Service Commission, Docket No. 07-035-04; "In the Matter of the Application of Rocky Mountain Power, a Division of PacifiCorp, for a Deferred Accounting Order To Defer the Costs of Loans Made to Grid West, the Regional Transmission Organization," Docket No. 06-035-163; "In the Matter of the Application of Rocky Mountain Power for an Accounting Order for Costs related to the Flooding of the Powerdale Hydro Facility," Docket No. 07-035-14. Direct testimony submitted September 10, 2007. Surrebuttal testimony submitted October 22, 2007. Cross examined October 30, 2007.

"In the Matter of General Adjustment of Electric Rates of East Kentucky Power Cooperative, Inc.," **Kentucky** Public Service Commission, Case No. 2006-00472. Direct testimony submitted July 5, 2007.

"In the Matter of the Application of Sempra Energy Solutions for a Certificate of Convenience and Necessity for Competitive Retail Electric Service," **Arizona** Corporation Commission, Docket No. E-03964A-06-0168. Direct testimony submitted July 3, 2007. Rebuttal testimony submitted January 17, 2008.

"Application of Public Service Company of Oklahoma for a Determination that Additional Electric Generating Capacity Will Be Used and Useful," **Oklahoma** Corporation Commission, Cause No. PUD 200500516; "Application of Public Service Company of Oklahoma for a Determination that Additional Baseload Electric Generating Capacity Will Be Used and Useful," Cause No. PUD 200600030; "In the Matter of the Application of Oklahoma Gas and Electric Company for an Order Granting Pre-Approval to Construct Red Rock Generating Facility and Authorizing a Recovery Rider," Cause No. PUD200700012. Responsive testimony submitted May 21, 2007. Cross examined July 26, 2007.

"Application of Nevada Power Company for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto," Public Utilities Commission of **Nevada**, Docket No. 06-11022. Direct testimony submitted March 14, 2007 (Phase III – revenue requirements) and March 19,

2007 (Phase IV – rate design). Cross examined April 10, 2007 (Phase III – revenue requirements) and April 16, 2007 (Phase IV – rate design).

“In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service,” **Arkansas** Public Service Commission, Docket No. 06-101-U. Direct testimony submitted February 5, 2007. Surrebuttal testimony submitted March 26, 2007.

“Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Rule 42T Application to Increase Electric Rates and Charges,” Public Service Commission of **West Virginia**, Case No. 06-0960-E-42T; “Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Information Required for Change of Depreciation Rates Pursuant to Rule 20,” Case No. 06-1426-E-D. Direct and rebuttal testimony submitted January 22, 2007.

“In the Matter of the Tariffs of Aquila, Inc., d/b/a Aquila Networks-MPS and Aquila Networks-L&P Increasing Electric Rates for the Services Provided to Customers in the Aquila Networks-MPS and Aquila Networks-L&P Missouri Service Areas,” **Missouri** Public Service Commission, Case No. ER-2007-0004. Direct testimony submitted January 18, 2007 (revenue requirements) and January 25, 2007 (revenue apportionment). Supplemental direct testimony submitted February 27, 2007.

“In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103, **Arizona** Corporation Commission, Docket No. E-01933A-05-0650. Direct testimony submitted January 8, 2007. Surrebuttal testimony filed February 8, 2007. Cross examined March 8, 2007.

“In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company’s Missouri Service Area,” **Missouri** Public Service Commission, Case No. ER-2007-0002. Direct testimony submitted December 15, 2006 (revenue requirements) and December 29, 2006 (fuel adjustment clause/cost-of-service/rate design). Rebuttal testimony submitted February 5, 2007 (cost-of-service). Surrebuttal testimony submitted February 27, 2007. Cross examined March 21, 2007.

“In the Matter of Application of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc. for an Adjustment of Electric Rates,” **Kentucky** Public Service Commission, Case No. 2006-00172. Direct testimony submitted September 13, 2006.

“In the Matter of Appalachian Power Company’s Application for Increase in Electric Rates,” **Virginia** State Corporation Commission, Case No. PUE-2006-00065. Direct testimony submitted September 1, 2006. Cross examined December 7, 2006.

“In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property for Ratemaking Purposes, to Fix a Just and Reasonable

Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744, **Arizona** Corporation Commission,” Docket No. E-01345A-05-0816. Direct testimony submitted August 18, 2006 (revenue requirements) and September 1, 2006 (cost-of-service/rate design). Surrebuttal testimony submitted September 27, 2006. Cross examined November 7, 2006.

“Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No 1454 – Electric,” **Colorado** Public Utilities Commission, Docket No. 06S-234EG. Answer testimony submitted August 18, 2006.

“Portland General Electric General Rate Case Filing,” Public Utility Commission of **Oregon**, Docket No. UE-180. Direct testimony submitted August 9, 2006. Joint testimony regarding stipulation submitted August 22, 2006.

“2006 Puget Sound Energy General Rate Case,” **Washington** Utilities and Transportation Commission, Docket Nos. UE-060266 and UG-060267. Response testimony submitted July 19, 2006. Joint testimony regarding stipulation submitted August 23, 2006.

“In the Matter of PacifiCorp, dba Pacific Power & Light Company, Request for a General Rate Increase in the Company’s Oregon Annual Revenues,” Public Utility Commission of **Oregon**, Docket No. UE-179. Direct testimony submitted July 12, 2006. Joint testimony regarding stipulation submitted August 21, 2006.

“Petition of Metropolitan Edison Company for Approval of a Rate Transition Plan,” **Pennsylvania** Public Utilities Commission, Docket Nos. P-00062213 and R-00061366; “Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan,” Docket Nos. P-00062214 and R-00061367; Merger Savings Remand Proceeding, Docket Nos. A-110300F0095 and A-110400F0040. Direct testimony submitted July 10, 2006. Rebuttal testimony submitted August 8, 2006. Surrebuttal testimony submitted August 18, 2006. Cross examined August 30, 2006.

“In the Matter of the Application of PacifiCorp for approval of its Proposed Electric Rate Schedules & Electric Service Regulations,” **Utah** Public Service Commission, Docket No. 06-035-21. Direct testimony submitted June 9, 2006 (Test Period). Surrebuttal testimony submitted July 14, 2006.

“Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders,” **Utah** Public Service Commission, Docket No. 05-057-T01. Direct testimony submitted May 15, 2006. Rebuttal testimony submitted August 8, 2007. Cross examined September 19, 2007.

"Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Power Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP, Proposed General Increase in Rates for Delivery Service (Tariffs Filed December 27, 2005)," **Illinois** Commerce Commission, Docket Nos. 06-0070, 06-0071, 06-0072. Direct testimony submitted March 26, 2006. Rebuttal testimony submitted June 27, 2006.

"In the Matter of Appalachian Power Company and Wheeling Power Company, both dba American Electric Power," Public Service Commission of **West Virginia**, Case No. 05-1278-E-PC-PW-42T. Direct and rebuttal testimony submitted March 8, 2006.

"In the Matter of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota," **Minnesota** Public Utilities Commission, Docket No. G-002/GR-05-1428. Direct testimony submitted March 2, 2006. Rebuttal testimony submitted March 30, 2006. Cross examined April 25, 2006.

"In the Matter of the Application of Arizona Public Service Company for an Emergency Interim Rate Increase and for an Interim Amendment to Decision No. 67744," **Arizona** Corporation Commission, Docket No. E-01345A-06-0009. Direct testimony submitted February 28, 2006. Cross examined March 23, 2006.

"In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in Their Charges for Electric Service," State Corporation Commission of **Kansas**, Case No. 05-WSEE-981-RTS. Direct testimony submitted September 9, 2005. Cross examined October 28, 2005.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Combined Cycle Electric Generating Facility," Public Utilities Commission of **Ohio**," Case No. 05-376-EL-UNC. Direct testimony submitted July 15, 2005. Cross examined August 12, 2005.

"In the Matter of the Filing of General Rate Case Information by Tucson Electric Power Company Pursuant to Decision No. 62103," **Arizona** Corporation Commission, Docket No. E-01933A-04-0408. Direct testimony submitted June 24, 2005.

"In the Matter of Application of The Detroit Edison Company to Unbundle and Realign Its Rate Schedules for Jurisdictional Retail Sales of Electricity," **Michigan** Public Service Commission, Case No. U-14399. Direct testimony submitted June 9, 2005. Rebuttal testimony submitted July 1, 2005.

"In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-14347. Direct testimony submitted June 3, 2005. Rebuttal testimony submitted June 17, 2005.

"In the Matter of Pacific Power & Light, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE 170. Direct testimony submitted May 9, 2005. Surrebuttal testimony submitted June 27, 2005. Joint testimony regarding partial stipulations submitted June 2005, July 2005, and August 2005.

"In the Matter of the Application of Trico Electric Cooperative, Inc. for a Rate Increase," **Arizona** Corporation Commission, Docket No. E-01461A-04-0607. Direct testimony submitted April 13, 2005. Surrebuttal testimony submitted May 16, 2005. Cross examined May 26, 2005.

"In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 04-035-42. Direct testimony submitted January 7, 2005.

"In the Matter of the Application by Golden Valley Electric Association, Inc., for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates," Regulatory Commission of **Alaska**, Docket No. U-4-33. Direct testimony submitted November 5, 2004. Cross examined February 8, 2005.

"Advice Letter No. 1411 - Public Service Company of Colorado Electric Phase II General Rate Case," **Colorado** Public Utilities Commission, Docket No. 04S-164E. Direct testimony submitted October 12, 2004. Cross-answer testimony submitted December 13, 2004. Testimony withdrawn January 18, 2005, following Applicant's withdrawal of testimony pertaining to TOU rates.

"In the Matter of Georgia Power Company's 2004 Rate Case," **Georgia** Public Service Commission, Docket No. 18300-U. Direct testimony submitted October 8, 2004. Cross examined October 27, 2004.

"2004 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-040641 and UG-040640. Response testimony submitted September 23, 2004. Cross-answer testimony submitted November 3, 2004. Joint testimony regarding stipulation submitted December 6, 2004.

"In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues," **Utah** Public Service Commission, Docket No. 02-035-04. Direct testimony submitted July 15, 2004. Cross examined July 19, 2004.

“In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Kentucky Utilities Company,” **Kentucky** Public Service Commission, Case No. 2003-00434. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

“In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company,” **Kentucky** Public Service Commission, Case No. 2003-00433. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

“In the Matter of the Application of Idaho Power Company for Authority to Increase Its Interim and Base Rates and Charges for Electric Service,” **Idaho** Public Utilities Commission, Case No. IPC-E-03-13. Direct testimony submitted February 20, 2004. Rebuttal testimony submitted March 19, 2004. Cross examined April 1, 2004.

“In the Matter of the Applications of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges, Including Regulatory Transition Charges Following the Market Development Period,” Public Utilities Commission of **Ohio**, Case No. 03-2144-EL-ATA. Direct testimony submitted February 6, 2004. Cross examined February 18, 2004.

“In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and For Approval of Purchased Power Contract,” **Arizona** Corporation Commission, Docket No. E-01345A-03-0437. Direct testimony submitted February 3, 2004. Rebuttal testimony submitted March 30, 2004. Direct testimony regarding stipulation submitted September 27, 2004. Responsive / Clarifying testimony regarding stipulation submitted October 25, 2004. Cross examined November 8-10, 2004 and November 29-December 3, 2004.

“In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.,” **Michigan** Public Service Commission, Case No. U-13808. Direct testimony submitted December 12, 2003 (interim request) and March 5, 2004 (general rate case).

“In the Matter of PacifiCorp’s Filing of Revised Tariff Schedules,” Public Utility Commission of **Oregon**, Docket No. UE-147. Joint testimony regarding stipulation submitted August 21, 2003.

"Petition of PSI Energy, Inc. for Authority to Increase Its Rates and Charges for Electric Service, etc.," **Indiana** Utility Regulatory Commission, Cause No. 42359. Direct testimony submitted August 19, 2003. Cross examined November 5, 2003.

"In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Certain of its Qualified Cost," **Michigan** Public Service Commission, Case No. U-13715. Direct testimony submitted April 8, 2003. Cross examined April 23, 2003.

"In the Matter of the Application of Arizona Public Service Company for Approval of Adjustment Mechanisms," **Arizona** Corporation Commission, Docket No. E-01345A-02-0403. Direct testimony submitted February 13, 2003. Surrebuttal testimony submitted March 20, 2003. Cross examined April 8, 2003.

"Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado, Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, Advice Letter No. 80 – Steam," **Colorado** Public Utilities Commission, Docket No. 02S-315 EG. Direct testimony submitted November 22, 2002. Cross-answer testimony submitted January 24, 2003.

"In the Matter of the Application of The Detroit Edison Company to Implement the Commission's Stranded Cost Recovery Procedure and for Approval of Net Stranded Cost Recovery Charges," **Michigan** Public Service Commission, Case No. U-13350. Direct testimony submitted November 12, 2002.

"Application of South Carolina Electric & Gas Company: Adjustments in the Company's Electric Rate Schedules and Tariffs," Public Service Commission of **South Carolina**, Docket No. 2002-223-E. Direct testimony submitted November 8, 2002. Surrebuttal testimony submitted November 18, 2002. Cross examined November 21, 2002.

"In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 02-057-02. Direct testimony submitted August 30, 2002. Rebuttal testimony submitted October 4, 2002.

"The Kroger Co. v. Dynegy Power Marketing, Inc.," **Federal Energy Regulatory Commission**, EL02-119-000. Confidential affidavit filed August 13, 2002.

"In the matter of the application of Consumers Energy Company for determination of net stranded costs and for approval of net stranded cost recovery charges," **Michigan** Public Service Commission, Case No. U-13380. Direct testimony submitted August 9, 2002. Rebuttal testimony submitted August 30, 2002. Cross examined September 10, 2002.

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," **Colorado** Public Utilities Commission, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," **Arizona** Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002 (APS variance request); May 29, 2002 (APS Track A proceeding/market power issues); and July 28, 2003 (Arizona ISA). Rebuttal testimony submitted August 29, 2003 (Arizona ISA). Cross examined June 21, 2002 (APS Track A proceeding/market power issues) and September 12, 2003 (Arizona ISA).

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of **Nevada**, PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14000-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149," Public Utility Commission of **Oregon**, Docket No. UE-115. Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," **Arizona** Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," **Salt River Project** Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," **Arizona** Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," **Utah** Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," **Arizona** Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-

0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," **Salt River Project** Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," **Salt River Project** Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," **New York** Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," **Utah** Public Service Commission, Docket No. 96-2018-01. Direct testimony submitted July 8, 1996.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," **Wyoming** Public Service Commission, Docket No. 2000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 7, 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," **Utah** Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," **Utah** Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," **Utah** Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," **Utah** Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," **Utah** Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," **Federal Energy Regulatory Commission**, Docket No. RM87-12-000. Statement on behalf of State of Utah delivered March 27, 1987, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," **Utah** Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," **Utah** Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," **Utah** Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," **Utah** Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for leveled contracts) and November 17, 1986 (avoided costs). Cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for leveled contracts) and December 16-17, 1986 (avoided costs).

#### **OTHER RELATED ACTIVITY**

Participant, Oregon Direct Access Task Force (UM 1081), May 2003 to November 2003.

Participant, Michigan Stranded Cost Collaborative, March 2003 to March 2004.

Member, Arizona Electric Competition Advisory Group, December 2002 to present.

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Member, Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to December 1999. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to September 1998.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an \$85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate Delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

# Summary of AECC Revenue Requirement Adjustments

Test Year Ended December 31, 2006  
(Thousands of Dollars)

As Filed by TEP

Line No.	Description	ACC Jurisdiction			Line No.
		Original Cost			
		Excluding DSM & CTC	Excluding CTC Including DSM	Including DSM & CTC	
1	Adjusted Rate Base	\$982,734 (a)	\$982,734	\$982,734	1
2	Adjusted Operating Income	(13,173) (b)	(\$9,883)	\$44,082	2
3	Current Rate of Return (2/1)	-1.34%	-1.01%	4.49%	3
4	Required Operating Income	\$82,069	\$82,069	\$82,069	4
5	Required Rate of Return (4/1)	8.35%	8.35%	8.35%	5
6	Operating Income Deficiency	\$95,242	\$91,952	\$37,987	6
7	Gross Revenue Conversion Factor	1.6609 (d)	1.6609	1.6609	7
8	Increase in Gross Revenue Requirement Excluding TCRAC (6 x 7)	\$158,186	\$152,721	\$63,091	8
9	Present Revenues	\$691,451 (e)	\$696,916 (e)	\$786,546 (e)	9
10	Percent Change from Present Revs. (8/9)	22.88%	21.91%	8.02%	10
11	Termination Cost Regulatory Asset Revenue (TCRAC)	\$117,623 (f)	\$117,623 (f)	\$117,623 (f)	11
12	Increase in Gross Revenue Requirement Including TCRAC (8 + 11)	\$275,809	\$270,344	\$180,714	11
13	Percent Change from Present Revs. (12/9)	39.89%	38.79%	22.98%	12

## Supporting Schedules

- (a) TEP Schedule B-1
- (b) TEP Schedule C-1
- (c) TEP Schedule D-1
- (d) TEP Schedule C-3
- (e) TEP Schedule H-1
- (f) TEP Schedule H-2 TCRAC, p. 3 of 3 Workpaper

# Summary of AECC Revenue Requirement Adjustments

Test Year Ended December 31, 2006  
(Thousands of Dollars)

## As Adjusted by AECC

Line No.	Description	ACC Jurisdiction			Line No.
		Excluding DSM & CTC	Excluding CTC Including DSM	Including DSM & CTC	
1	Adjusted Rate Base	\$1,018,008	(a)&(b)	\$1,018,008	1
2	Adjusted Operating Income	29,852	(c)	\$33,142	2
3	Current Rate of Return (2/1)	2.93%		3.26%	3
4	Target Operating Income (5 x 1)	\$85,015		\$85,015	4
5	Target Rate of Return	8.35%	(d)	8.35%	5
6	Operating Income Deficiency (4 - 2)	\$55,163		\$51,873	6
7	Gross Revenue Conversion Factor	1.6609	(e)	1.6609	7
8	Increase in Gross Revenue Requirement (6 x 7)	\$91,619		\$86,154	8
9	Present Revenues	\$691,451	(f)	\$696,916	9
10	Percent Change from Present Revs. (8/9)	13.25%		12.36%	10
11	TEP Claimed Revenue Deficiency	\$275,809		\$270,344	11
12	Percent Change from Present Revs. (11/9)	39.89%		38.79%	12
13	AECC Change from TEP Claimed Revenue Deficiency (8 - 11)	(\$184,190)		(\$184,190)	13
14	AECC Percent Change from TEP Claimed Revenue Deficiency (10 - 12)	-26.64%		-26.43%	14

### Supporting Schedules

- (a) TEP Schedule B-1
- (b) AECC Schedule KCH-1, p. 4
- (c) AECC Schedule KCH-1, p. 3
- (d) TEP Schedule D-1
- (e) TEP Schedule C-3
- (f) TEP Schedule H-1

## Summary of AECC Revenue Requirement Adjustments

## Operating Revenues and Expenses

Test Year Ended December 31, 2006  
(Thousands of Dollars)

Line No.	Description	TEP Unadjusted (a)	TEP Pro Forma Adjustments (a)	TEP Total Adjusted (a)	TEP ACC Jurisdiction (a)	AECC Springerville No. 1 Pro Forma Adjustment (b)	AECC Short Term Sales Reversal (b)	AECC Implementation Cost Regulatory Asset (b)	AECC Luna Plant Adjustment Reversal (b)	AECC ACC Jurisdiction	Line No.
1	Operating Revenues										1
2	Electric Retail Revenues	\$774,470	(\$83,019)	\$691,451	\$691,451	\$0	\$0	0	0	\$691,451	2
3	Sales for Resale	242,187	(183,785)	58,402	0	0	\$73,439	0	0	\$73,439	3
4	Other Operating Revenue	48,764	(\$14,222)	34,542	21,280	0	\$0	0	0	\$21,280	4
	Total Operating Revenues	1,065,421	(281,026)	784,395	712,731	0	73,439	0	0	786,170	
5	Operating Expenses										5
6	Fuel Expense	278,776	(12,821)	265,955	238,199	0	28,799	0	0	\$266,998	6
7	Purchased Power - Demand	13,740	16,894	30,634	28,959	0	0	0	(15,088)	\$13,872	7
8	Purchased Power - Energy	163,607	(123,572)	40,035	35,857	0	20,762	0	0	\$56,618	8
9	Other Operations and Maintenance Expense	326,899	(11,596)	315,303	368,170	(30,357)	0	0	1,981	\$338,794	9
10	Depreciation	89,928	(7,488)	82,440	57,914	0	0	(3,900)	0	\$54,014	10
11	Taxes Other than Income Taxes	38,404	(2,573)	35,831	29,092	0	0	0	8	\$29,100	11
12	Income Taxes	45,292	(88,555)	(43,263)	(32,286)	12,021	9,456	1,544	5,187	(\$4,078)	12
	Total Operating Expenses	957,448	(199,708)	757,738	725,904	(18,336)	59,016	(2,355)	(7,512)	756,318	
13	Operating Income	107,975	(\$81,318)	\$26,657	(\$13,173)	\$18,536	\$14,423	\$2,355	\$7,512	\$28,852	13
14	Other Income and Deductions										
15	Allowance for Equity Funds	1,476									
16	Other - Net	11,789									
	Total Other Income and Deductions	13,265									
17	Income Before Interest Expense	121,240									
18	Interest Expense										
19	Interest on Long-Term Debt	44,102									
20	Interest on Short-Term Debt	1,216									
21	Other Interest Expense	10,447									
22	Allowance for Borrowed Funds	(1,270)									
	Total Interest Expense	54,495									
23	Income Before Cumulative Effect of Accounting Change	66,745									
24	Cumulative Effect of Accounting Change - Net of Tax	0									
25	Net Income Available for Common Stock	\$66,745									

Supporting Schedules

(a) TEP Schedule C-1

(b) AECC Schedule KCH-1, p. 4

Recap Schedules

# Summary of AECC Revenue Requirement Adjustments

## AECC Recommended Rate Base Adjustments

Line No.		ACC Jurisdiction				Line No.
		AECC Add'l Springerville Unit No. 1	AECC Short Term Sales Exclusion Reversal	AECC Implementation Cost Regulatory Asset	AECC Luna Plant Adjustment Reversal	
		(a)	(b)	(c)	(d)	
1	Rate Base	0	0	(11,181)	46,456	1

## AECC Recommended Revenue and Expense Adjustments

Line No.		ACC Jurisdiction				Line No.
		AECC Add'l Springerville Unit No. 1	AECC Short Term Sales Exclusion Reversal	AECC Implementation Cost Regulatory Asset	AECC Luna Plant Adjustment Reversal	
		(a)	(b)	(c)	(d)	
2	Operating Revenues					2
3	Electric Retail Revenues	0	0	0	0	3
4	Sales for Resale	0	73,439	0	0	4
5	Other Operating Revenue	0	0	0	0	5
6	Total Operating Revenues	0	73,439	0	0	6
7	Operating Expenses					7
8	Fuel Expense	0	28,799	0	0	8
9	Purchased Power - Demand	0	0	0	(15,088)	9
10	Purchased Power - Energy	0	20,762	0	0	10
11	Other Operations & Maintenance Expense	(30,357)	0	0	1,981	11
12	Depreciation and Amortization	0	0	(3,900)	0	12
13	Taxes Other than Income	0	0	0	8	13
14	Income Taxes	12,021	9,456	1,544	5,187	14
15	Total Operating Expenses	(18,336)	59,016	(2,355)	(7,912)	15
16	Operating Income	18,336	14,423	2,355	7,912	16

### Supporting Schedules

- (a) AECC Schedule KCH-2, p. 1
- (b) AECC Schedule KCH-3, p. 1
- (c) AECC Schedule KCH-4, p. 1
- (d) AECC Schedule KCH-5, p. 1

## AECC Adjustment to Springerville Unit No. 1 Fixed Cost Recovery

Jurisdictional Demand Allocation Factor      94.53%      (b)  
Jurisdictional O&M Allocation Factor      95.68%      (b)

Line No.	Total Company		Jurisdictional	Line No.
	AECC Springerville Unit No. 1 (a)	AECC Springerville Unit No. 1		
1	Operating Revenues			1
2	Electric Retail Revenues	0	0	2
3	Sales for Resale	0	0	3
4	Other Operating Revenue	0	0	4
5	Total Operating Revenues	0	0	5
6	Operating Expenses			6
7	Fuel Expense	0	0	7
8	Purchased Power - Demand	0	0	8
9	Purchased Power - Energy	0	0	9
10	Other Operations & Maintenance Expense	(32,095)	(30,357)	10
11	Depreciation and Amortization	0	0	11
12	Taxes Other than Income	0	0	12
13	Income Taxes	12,710	12,021	13
14	Total Operating Expenses	(19,385)	(18,336)	14
15	Operating Income	19,385	18,336	15
16	Gross Revenue Conversion Factor		1.6609 (c)	16
17	Impact on Revenue Requirement (-15 x 16)		(30,453)	17

### Income Tax Calculation

Change in Revenue	0	0
Change in O&M Expenses	(32,095)	(30,357)
Change in Depreciation and Amortization	0	0
Change in Taxes, Other than Income	0	0

Change in Operating Income Before Income Taxes      32,095      30,357

### Income Tax Adjustments:

Change in Net Schedule M Items	0	0
Change in Synchronized Interest	0	0
Change in Taxable Operating Income	32,095	30,357
Effective FIT & SIT Tax Rate	39.600% (c)	39.600% (c)
Change in Income Tax Expense Before Credits	12,710	12,021
Change in Income Tax Credits	0	0
Total Change in Income Taxes	12,710	12,021

### Supporting Schedules/Data Source

- (a) TEP Income - Springerville Unit 1.xls  
(b) 2007 TEP Rev Req Model.xls  
(c) TEP Schedule C-3

**Adjustment to Springerville Unit No. 1 Fixed Cost Recovery  
Test Year Ended December 31, 2006**

Line No.	(b)	FERC (c)	(d)	TEP G/L <sup>1</sup> (e)	TEP Proposed Allowed <sup>1</sup> (f)	TEP Adjustment <sup>1</sup> (g)	AECC Proposed Allowed (h)	AECC Adjustment to TEP Proposed (i)	Line No. (j)
<b>Operations &amp; Maintenance</b>									
1		500		\$630,417	\$868,566	\$238,149	\$630,417	(\$238,149)	1
2		502		\$6,495,149	\$8,948,779	\$2,453,630	\$6,495,149	(\$2,453,630)	2
3		505		\$502,754	\$692,677	\$189,922	\$502,754	(\$189,922)	3
4		506		\$974,565	\$1,342,720	\$368,155	\$974,565	(\$368,155)	4
5		507	Lease Expense	\$61,857,188	\$85,224,576	\$23,367,388	\$61,857,188	(\$23,367,388)	5
6		510		\$761,665	\$1,049,394	\$287,729	\$761,665	(\$287,729)	6
7		511		\$503,659	\$693,923	\$190,264	\$503,659	(\$190,264)	7
8		512		\$6,860,839	\$9,452,613	\$2,591,774	\$6,860,839	(\$2,591,774)	8
9		513		\$1,071,214	\$1,475,879	\$404,665	\$1,071,214	(\$404,665)	9
10		514		\$1,575,182	\$2,170,229	\$595,046	\$1,575,182	(\$595,046)	10
11		O&M Sub-Total		<u>\$81,232,631</u>	<u>\$111,919,355</u>	<u>\$30,686,724</u>	<u>\$81,232,631</u>	<u>(\$30,686,724)</u>	11
<b>Administrative &amp; General</b>									
12		920		\$767,057	\$1,056,823	\$289,766	\$767,057	(\$289,766)	12
13		921		\$289,224	\$398,482	\$109,258	\$289,224	(\$109,258)	13
14		923		\$187,116	\$257,801	\$70,686	\$187,116	(\$70,686)	14
15		924		\$517,624	\$713,164	\$195,540	\$517,624	(\$195,540)	15
16		925		\$72,478	\$99,857	\$27,379	\$72,478	(\$27,379)	16
17		926		\$1,843,918	\$2,540,483	\$696,565	\$1,843,918	(\$696,565)	17
18		930		\$34,507	\$47,543	\$13,036	\$34,507	(\$13,036)	18
19		931		\$15,744	\$21,691	\$5,947	\$15,744	(\$5,947)	19
20		A&G Sub-Total		<u>\$3,727,668</u>	<u>\$5,135,845</u>	<u>\$1,408,177</u>	<u>\$3,727,668</u>	<u>(\$1,408,177)</u>	20
21	Total Adjustment to Cost of Service			<u>\$84,960,299</u>	<u>\$117,055,200</u>	<u>\$32,094,901</u>	<u>\$84,960,299</u>	<u>(\$32,094,901)</u>	21
22	SP Unit 1 Nameplate Rating (MW)			380					22
23	Cost per kW per Year			\$223.58	= [O&M + A&G] / Rating (MW) = Ln 21 + [Ln 22 x 1000]				23
24	Cost per kW per Month			\$18.63	= Cost per MW per year ÷ 12 = Ln 23 ÷ 12				24

**Calculation of Proposed Springerville Unit #1 Allowed Expenses**

25	(a) TEP Proposed Allowed SP1 Expenses	\$25.67	x	380	x	12	x	1,000	=	<u>\$117,055,200</u>	25
26	(b) AECC Proposed Allowed SP1 Expenses	\$18.63	x	380	x	12	x	1,000	=	<u>\$84,960,299</u>	26

**Data Source**

(1) TEP Pro Forma Adjustment Workpaper "Income - Springerville Unit 1.xls"

## AECC Adjustment to Short Term Sales Margin

		Jurisdictional Demand Allocation Factor	94.53%	(b)
		Total Company	Jurisdictional	
		AECC Short Term Sales Exclusion Reversal (a)	AECC Short Term Sales Exclusion Reversal	
Line No.				Line No.
1	Operating Revenues			1
2	Electric Retail Revenues	0	0	2
3	Sales for Resale	77,685	73,439	3
4	Other Operating Reveue	0	0	4
5	Total Operating Revenues	77,685	73,439	5
6	Operating Expenses			6
7	Fuel Expense	30,464	28,799	7
8	Purchased Power - Demand	0	0	8
9	Purchased Power - Energy	21,962	20,762	9
10	Other Operations & Maintenance Expense	0	0	10
11	Depreciation and Amortization	0	0	11
12	Taxes Other than Income	0	0	12
13	Income Taxes	10,003	9,456	13
14	Total Operating Expenses	62,429	59,016	14
15	Operating Income	15,256	14,423	15
16	Gross Revenue Conversion Factor		1.6609	(c) 16
17	Impact on Revenue Requirement (-17 x 18)		(23,954)	17
<u>Income Tax Calculation</u>				
	Change in Revenue	77,685	73,439	
	Change in O&M Expenses	52,426	49,561	
	Change in Depreciation and Amortization	0	0	
	Change in Taxes, Other than Income	0	0	
	Change in Operating Income Before Income Taxes	25,259	23,878	
Income Tax Adjustments:				
	Change in Net Schedule M Items	0	0	
	Change in Synchronized Interest	0	0	
	Change in Taxable Operating Income	25,259	23,878	
	Effective FIT & SIT Tax Rate	39.600%	39.600%	(c) (c)
	Change in Income Tax Expense Before Credits	10,003	9,456	
	Change in Income Tax Credits	0	0	
	Total Change in Income Taxes	10,003	9,456	

Supporting Schedules/Data Source

- (a) TEP Schedule C-2, p. 2 of 8
- (b) 2007 TEP Rev Req Model.xls
- (c) TEP Schedule C-3

## AECC Adjustment to Implementation Cost Regulatory Asset

		Jurisdictional Allocation Factor	100.00%	(b)
Line No.		Total Company	Jurisdictional	Line No.
		AECC Implementation Cost Regulatory Asset (a)	AECC Implementation Cost Regulatory Asset	
1	Rate Base	(11,181)	(11,181)	1
2	Operating Revenues			2
3	Electric Retail Revenues	0	0	3
4	Sales for Resale	0	0	4
5	Other Operating Revenue	0	0	5
6	Total Operating Revenues	<u>0</u>	<u>0</u>	6
7	Operating Expenses			7
8	Fuel Expense	0	0	8
9	Purchased Power - Demand	0	0	9
10	Purchased Power - Energy	0	0	10
11	Other Operations & Maintenance Expense	0	0	11
12	Depreciation and Amortization	(3,900)	(3,900)	12
13	Taxes Other than Income	0	0	13
14	Income Taxes	1,544	1,544	14
15	Total Operating Expenses	<u>(2,355)</u>	<u>(2,355)</u>	15
16	Operating Income	<u>2,355</u>	<u>2,355</u>	16
17	Gross Revenue Conversion Factor		1.6609	(c) 17
18	Impact on Revenue Requirement $(-[16 \times 17] + [8.35\% \times 1 \times 17])$		<span style="border: 1px solid black;">(5,463)</span>	18

### Income Tax Calculation

Change in Revenue	0	0
Change in O&M Expenses	0	0
Change in Depreciation and Amortization	(3,900)	(3,900)
Change in Taxes, Other than Income	<u>0</u>	<u>0</u>

Change in Operating Income Before Income Taxes 3,900

### Income Tax Adjustments:

Change in Net Schedule M Items	0	0
Change in Synchronized Interest	0	0
Change in Taxable Operating Income	3,900	3,900
Effective FIT & SIT Tax Rate	39.600% (c)	39.600% (c)
Change in Income Tax Expense Before Credits	1,544	1,544
Change in Income Tax Credits	0	0
Total Change in Income Taxes	1,544	1,544

### Supporting Schedules/Data Source

- (a) AECC ICRA Adjustment Workpaper
- (b) 2007 TEP Rev Req Model.xls
- (c) TEP Schedule C-3

AECC Regulatory Asset Adjustment  
Test Year Ended December 31, 2006

	TEP	AECC	AECC Adjustment
<b>Deferred Direct Access Costs</b>			
Balance of regulatory asset in FERC 182.3 (deferred amortization) @ 12/31/06	\$11,153,016	\$11,153,016	\$0
<b>Total Direct Access Costs to be recovered in Rate Base</b>	<b>\$11,153,016</b>	<b>\$11,153,016</b>	<b>\$0</b>
<b>TEP Adjustment to test year expense</b>	<b>/4</b>	<b>/4</b>	
Amortization of Direct Access Costs over 4 years.	\$2,788,254	\$2,788,254	\$0
<u>Explanation of reclass of intangible plant to regulatory asset:</u> The balance in the regulatory asset represents deferred amortization of the capitalized direct access costs.			
<b>Deferred Divestiture Costs</b>			
Balance of regulatory asset in FERC 182.3 (deferred amortization) @ 12/31/06	\$1,193,003	\$1,193,003	\$0
<b>Total Deferred Divestiture Costs to be recovered in Rate Base</b>	<b>\$1,193,003</b>	<b>\$1,193,003</b>	<b>\$0</b>
<b>TEP Adjustment to test year expense</b>	<b>/4</b>	<b>/4</b>	
Amortization of Deferred Divestiture Costs over 4 years.	\$298,251	\$298,251	\$0
<u>Reason for Adjustment</u> To increase rate base for divestiture costs deferred in accordance with Decision No. 60977 and Decision No. 62103.			
<b>Deferred GenCo Separation Costs</b>			
Balance of regulatory asset in FERC 182.3 (deferred amortization) @ 12/31/06	\$164,026	\$164,026	\$0
<b>Total Deferred GenCo Separation Costs to be recovered in Rate Base</b>	<b>\$164,026</b>	<b>\$164,026</b>	<b>\$0</b>
<b>TEP Adjustment to test year expense</b>	<b>/4</b>	<b>/4</b>	
Amortization of Deferred GenCo Separation Costs over 4 years.	\$41,007	\$41,007	\$0
<u>Reason for Adjustment</u> To increase rate base for GenCo separation costs deferred in accordance with Decision No. 62103.			
<b>San Juan Coal Contract Amendment</b>			
Contract Amendment Fee Paid	\$15,413,887		
Plus Transaction Costs (attorneys fees)	155,309		
Less Tax Refund	(838,107)		
<b>Total San Juan Contract Amendment Fees to be recovered in Rate Base</b>	<b>\$14,731,089</b>	<b>\$8,715,894</b>	<b>(\$6,015,195)</b>
<b>TEP Adjustment to test year expense</b>	<b>/4</b>	<b>/4</b>	
Amortization of San Juan Coal Contract Termination Costs over 4 years.	\$3,682,772	\$1,473,109	(\$2,209,663)
<u>Reason for Adjustment</u> To reflect in rate base the consideration paid to amend the former coal contract for the San Juan generation station.			

AECC Regulatory Asset Adjustment  
Test Year Ended December 31, 2006

	TEP	AECC	AECC Adjustment
<b>Sundt Coal Contract Termination Fee</b>			
Contract Fee Paid	\$11,250,000		
Plus Transaction Costs (economic consultant)	9,934		
<b>Total Sundt Coal Contract Termination Fee to be recovered in Rate Base</b>	<b>\$11,259,934</b>	<b>\$6,093,750</b>	<b>(\$5,166,184)</b>
<b>TEP Adjustment to test year expense</b>	<b>/4</b>	<b>/4</b>	
Amortization of Sundt Coal Termination Fee over 4 years.	\$2,814,984	\$1,125,000	(\$1,689,984)
<u>Reason for Adjustment</u>			
To reflect in rate base the consideration paid to terminate the coal contract for the Sundt generation station.			
<b>Deferred Desert Star and West Connect Funding</b>			
Desert Star long term receivable	\$446,129	\$446,129	\$0
Desert Star long term interest receivable	251,970	251,970	0
West Connect charges	273,445	273,445	0
Plus Related Outside Counsel Costs	731,254	731,254	0
<b>Total Deferred Desert Star and West Connect Funding to be recovered in Rate Base.</b>	<b>\$1,702,798</b>	<b>\$1,702,798</b>	<b>\$0</b>
<b>TEP Adjustment to test year expense</b>	<b>/4</b>	<b>/4</b>	
Amortization of Deferred Desert Star and West Connect Funding.	\$425,700	\$425,700	\$0
<u>Reason for Adjustment</u>			
To reflect in rate base the funding and related costs for Desert Star and West Connect.			
<b>Financing Costs - Generation</b>			
Financing Costs - Generation	\$7,251,358	\$7,251,358	\$0
<b>Total Deferred Financing Costs - Generation to be recovered in Rate Base.</b>	<b>\$7,251,358</b>	<b>\$7,251,358</b>	<b>\$0</b>
<b>TEP Adjustment to test year expense</b>	<b>/4</b>	<b>/4</b>	
Amortization of Financing Costs - Generation.	\$1,812,840	\$1,812,840	\$0
<u>Reason for Adjustment</u>			
To reflect in rate base the financing costs for generation.			
<b>Total 182.3 Regulatory Assets</b>	<b>\$47,455,224</b>	<b>\$36,273,845</b>	<b>(\$11,181,379)</b>
<b>Annual Amortization</b>	<b>\$11,863,806</b>	<b>\$7,964,159</b>	<b>(\$3,899,647)</b>

## AECC Adjustment to Luna Plant

		Jurisdictional Demand Allocation Factor	94.53%	(b)
Line No.		Total Company	Jurisdictional	Line No.
		AECC Luna Plant Adjustment Reversal (a)	AECC Luna Plant Adjustment Reversal	
1	Rate Base (Luna OCRB + Luna ADIT)	49,141	46,456	1
2	Operating Revenues			2
3	Electric Retail Revenues	0	0	3
4	Sales for Resale	0	0	4
5	Other Operating Revenue	0	0	5
6	Total Operating Revenues	<u>0</u>	<u>0</u>	6
7	Operating Expenses			7
8	Fuel Expense	0	0	8
9	Purchased Power - Demand	(15,960)	(15,088)	9
10	Purchased Power - Energy	0	0	10
11	Other Operations & Maintenance Expense	2,096	1,981	11
12	Depreciation and Amortization	0	0	12
13	Taxes Other than Income	8	8	13
14	Income Taxes	5,487	5,187	14
15	Total Operating Expenses	<u>(8,369)</u>	<u>(7,912)</u>	15
16	Operating Income	<u>8,369</u>	<u>7,912</u>	16
17	Gross Revenue Conversion Factor		1.6609	(c) 17
18	Impact on Revenue Requirement $(-[16 \times 17] + [8.35\% \times 1 \times 17])$		<u>(6,697)</u>	18
<b>Income Tax Calculation</b>				
	Change in Revenue	0	0	
	Change in O&M Expenses	(13,864)	(13,106)	
	Change in Depreciation and Amortization	0	0	
	Change in Taxes, Other than Income	8	8	
	Change in Operating Income Before Income Taxes	13,856	13,099	
<b>Income Tax Adjustments:</b>				
	Change in Net Schedule M Items	0	0	
	Change in Synchronized Interest	0	0	
	Change in Taxable Operating Income	13,856	13,099	
	Effective FIT & SIT Tax Rate	39.600%	39.600%	(c) (c)
	Change in Income Tax Expense Before Credits	5,487	5,187	
	Change in Income Tax Credits	0	0	
	Total Change in Income Taxes	5,487	5,187	

**Supporting Schedules/Data Source**

- (a) TEP Luna Plant and ADIT Adjustment Workpapers
- (b) 2007 TEP Rev Req Model.xls
- (c) TEP Schedule C-3

# AECC Adjustments to Base Fuel Cost

Line No.	FERC Account	Expense	TEP Cost of Service ACC Jurisdiction Adjusted \$000	AECC Short Term Sales Reversal \$000	AECC Luna Plant Adjustment Reversal \$000	AECC Cost of Service ACC Jurisdiction Adjusted \$000	Line No.
1	447	Sales for Resale - PPFAC Eligible	\$ -	\$73,439 (b)		\$73,439	1
2	501	Fuel - PPFAC Eligible	\$ 214,138 (a)			\$242,936	2
3	547	Fuel - PPFAC Eligible	\$ 24,061 (a)	28,799 (b)		\$24,061	3
4	555	Purchase Power, Demand - PPFAC Eligible	\$ 28,959 (a)		(15,088) (b)	\$13,872	4
5	555	Purchase Power, Energy - PPFAC Eligible	\$ 35,857 (a)	20,762 (b)		\$56,618	5
6	565	Transmission - PPFAC Eligible	\$ 4,511 (a)			\$4,511	6
7		Base Cost	\$ 307,526	\$ 49,561	\$ (15,088)	\$ 341,998	7
8		Net Base FFPAC Eligible Costs	\$ 307,526	\$ (23,878)	\$ (15,088)	\$ 268,559	8
9		Adjusted Retail Sales, GWh	9,319 (a)	9,319	9,319	9,319	9
10		Base Fuel Cost per KWh (¢/kWh)	3.30	(0.26)	(0.16)	2.88	10

## Supporting Schedules

- (a) TEP Exhibit DGH-8  
(b) AECC Exhibit KCH-1, p. 3